



ENVIRONMENTAL SERVICES INCORPORATED

**PHASE II – SUBSURFACE PRODUCT RECOVERY
SIMULATION REPORT**

**FOR
COMMONWEALTH OIL REFINING COMPANY, INC.
PEÑUELAS, PUERTO RICO**

DSM PROJECT NO. 1116-01

APRIL 1998

PREPARED BY:

DSM ENVIRONMENTAL SERVICES, INC.



ENVIRONMENTAL SERVICES INC.

April 30, 1998

Mr. Richard Krauser
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
Region II
HAZARDOUS WASTE FACILITY BRANCH
290 Broadway, 22nd Floor
New York, NY 10007-1866

Re: Commonwealth Oil Refining Company
Phase II: Subsurface Product Delineation and Formation Evaluation Work Plan -
Phase II - Subsurface Product Recovery Simulation Report
EPA I. D. PRD091017228

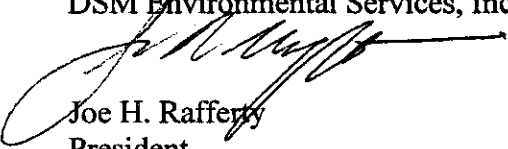
Dear Mr. Krauser:

DSM Environmental Services, Inc. (DSM), on behalf of the Commonwealth Oil Refining Company (CORCO) presents the following Phase II – Product Recovery Simulation Report ("Report") describing the findings of the computer simulation of recovery scenarios for the hydrocarbon product lens that is located beneath the CORCO facility in Peñuelas, Puerto Rico. This work was performed in accordance with EPA correspondence of April 24, 1996. This Report completes the subsurface product recovery simulation (Step #3) of the ***Phase II: Subsurface Product Delineation and Formation Evaluation Work Plan*** as approved by EPA.

This report is presented for your review and comment. In accordance with the schedule presented to the U.S. EPA on December 19, 1997, the agency has 45 days allotted in the schedule in which to review and comment on this report. DSM and CORCO are prepared to commence Step #4 of the ***Phase II: Subsurface Product Delineation and Formation Evaluation Work Plan; Subsurface Product Recovery System Preliminary Design*** upon receipt of your comments on this report.

In the meantime, if you have any questions or comments please call us at (281) 870 – 8676.

Sincerely,
DSM Environmental Services, Inc.



Joe H. Rafferty
President

Attachments

cc: Mr. Israel Torres - PREQB
Mr. Dale Byars - CORCO
Mr. Roberto Gratacos - CORCO
Mr. Edert Ortiz - CORCO
DSM File: 1116-01/ 22.0

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TABLE OF CONTENTS

1. INTRODUCTION.....	1
2. CORCO FACILITY GEOLOGY & HYDROGEOLOGY	1
3. SUBSURFACE HYDROCARBON PRODUCT DISTRIBUTION	2
3.1. AREAL EXTENT	2
3.2. SUBSURFACE OCCURRENCE	3
4. MODEL SELECTION	5
5. RECOVERY MODELING DATA AND ASSUMPTIONS.....	5
5.1. RECOVERY MODELING DATA	5
5.2. RECOVERY MODEL CALIBRATION	7
6. PRODUCT RECOVERY SIMULATION.....	8
6.1. RECOVERY WELL DISTRIBUTION	8
6.2. HYDROCARBON PRODUCT RECOVERY	9
7. MODEL VERIFICATION	9
8. CONCLUSIONS	10
9. REFERENCES.....	12

LIST OF TABLES

TABLE 1 – COMPARISON OF MEASURED PRODUCT THICKNESS IN PD-10 AND PD-25.....	4
TABLE 2 – HYDRAULIC CONDUCTIVITY COMPARISONS.....	7

LIST OF FIGURES

FIGURE 1 – MONITORING WELL LOCATION PLAN	
FIGURE 2 – EXTENT OF HYDROCARBON PRODUCT	
FIGURE 3 – SIMULATED HYDROCARBON PRODUCT DISTRIBUTION, BEFORE REMEDIATION	
FIGURE 4 – SIMULATED HYDROCARBON PRODUCT DISTRIBUTION, AFTER REMEDIATION	
FIGURE 5 – SIMULATED HYDROCARBON PRODUCT DISTRIBUTION, AFTER REMEDIATION	
FIGURE 6 – SIMULATED HYDROCARBON PRODUCT DISTRIBUTION, AFTER REMEDIATION	

LIST OF APPENDICES

APPENDIX A – HYDROCARBON PRODUCT THICKNESS IN THE FORMATION	
APPENDIX B – GROUND WATER AND HYDROCARBON PRODUCT RECOVERY RATE FOR EPRB-3 AND EPRB-6	
APPENDIX C – HYDROCARBON PRODUCT RECOVERY TEST ANALYSES	
APPENDIX D – MODEL CALIBRATION PARAMETERS	
APPENDIX E – MODEL VERIFICATION	

1. INTRODUCTION

Pursuant to the schedule of tasks presented to the U.S. Environmental Protection Agency, on December 19, 1997, DSM Environmental Services, Inc. (DSM) has constructed and analyzed computer simulations of recovery scenarios for the hydrocarbon product that has been found on the ground water within the Commonwealth Oil Refining Company's (CORCO) facility, located in Peñuelas, Puerto Rico. This computer simulation is Step 3 of the "Phase II – Subsurface Product Delineation and Formation Evaluation Work Plan". Previous studies by DSM and others identified the presence of hydrocarbon product in the subsurface. This hydrocarbon product is contained in a lens-shaped mass that is floating on the ground water table. The objective of the computer simulation was to perform analysis of product recovery scenarios based on empirical data and select an appropriate product recovery scenario to optimize the recovery of subsurface product from the CORCO facility.

DSM conducted two recovery tests to acquire specific data required to perform these simulations and analyses. The recovery tests were conducted in wells that were installed within the facility for that purpose. Data from the recovery tests were analyzed and used to calibrate the computer model of the product lens, to develop three potential recovery scenarios using conventional product recovery technology, and to select the most efficient recovery scenario for implementation.

2. CORCO FACILITY GEOLOGY & HYDROGEOLOGY

The majority of the facility is located on a surface exposure of the Ponce Limestone. The Ponce Limestone in the facility area is a Miocene age, back bay, and/or back reef deposit that is composed primarily of calcareous clay with filled tidal channels, buried tidal flats, small reef structures, isolated corals, numerous fossils, and some solution and/or structural cavities.

The entire area has been densely faulted during tectonic uplift. One fault in the northeast portion of the facility, identified on the USGS "*Geologic Map of the Peñuelas and Punta Cuchara Quadrangles*" (Krushensky, and Monroe, 1978), has a surface exposure in the southwestern part of the facility in the area of wells PD-10 and PT-3 (**Figure 1 – Monitoring Well Location Plan**). The fault is oriented north-northeast - south-southwest and dips very steeply to the northwest. Faulting exposed in outcrops of the Ponce Limestone along Highway 2, east of the facility, indicates that the north-northeast - south-southwest direction is the primary orientation and the dips are similar to the fault orientation in the facility. Other parallel and offset faults and joints are evident within the facility boundaries as well as outside of the facility so, for clarity, the above referenced fault is referred to as the "central fault". Vertical movement of water through the formation appears to be primarily along secondary permeability features such as joints and faults.

Other, secondary permeability development, in the form of solution cavities, have been observed along the fault and joint exposures within the facility and outside of the facility. These cavities were formed by solutioning of the limestone or during the deposition of the clays and subsequent submarine landslides. The observed solution cavities are widely spaced, do not appear to be connected in any sort of continuous, cave-like formation and do not

contain ground water if they are above the water table. The solution cavities associated with the fault structures in the Ponce Limestone appear to be formed by water solutioning of the limestone and follow the fault orientation.

Sustained pumping rates for water wells in the Ponce Limestone are generally 1 to 30 gallons per minute (gpm), although the higher volume is attributed to wells pumping from a combination of the Tallaboa River alluvium and the Ponce limestone (Grossman, et.al., 1972). Outcrops of the Ponce Limestone in the facility and surrounding areas looks like a typical, back bay or back-of-reef, marine, calcareous clay formation wherein the primary permeability should be in the range of 1×10^{-7} to 1×10^{-10} cm/sec (Driscoll, 1987). The occurrence of small reef structures and some more granular facies in the Ponce Limestone may increase the average, primary hydraulic conductivity somewhat, but not more than two or three orders of magnitude. Calcareous, marine clay deposits such as those found in the facility and in surrounding areas typically would not produce water in excess of 1 to 5 gpm except from secondary permeability features such as fractures or voids.

Horizontal movement of water through the Ponce Limestone appears to be controlled by the occurrence of a marine clay layer in the sediments to the south of Highway 127 that prevents the migration of hydrocarbon product to the south of the highway (DSM, 1998). This marine clay acts as a confining or semi-confining layer for the ground water south of the highway, whereas the ground water north of the highway is unconfined. In the Ponce Limestone in the facility area, the ground water movement appears to be generally to the west-southwest.

3. SUBSURFACE HYDROCARBON PRODUCT DISTRIBUTION

3.1. AREAL EXTENT

Hydrocarbon product was found on the water table during the installation of monitoring wells at the CORCO facility (DSM 1994). The subsurface product was analyzed and found to be primarily a mix of hydrocarbon fuel products with smaller amounts of heavier and lighter hydrocarbon products (DSM 1994). As indicated in previous reports, and as confirmed by this investigation, the phase-separated product plume on the ground water at the CORCO facility is confined to an area north of Highway 127. It is bounded by the Shell Oil Company property on the west and the HERCOR property on the east. Past subsurface investigations, conducted at the Shell Property (*Environmental Property Assessment Report, Shell Fuel Terminal, Guayanilla, Puerto Rico*, March 5, 1992) and subsequent letter reports in 1993, 1995, and 1996, report the presence of free-phase product underlying the Shell property. However, no confirmatory sampling of existing wells on the Shell property was conducted to ascertain the current presence, or absence, of free-phase product. For the purposes of this simulation, the hydrocarbon product distribution shown on **Figure 2 – Extent of Hydrocarbon Product** has been used. **Figure 2** presents a representation of the horizontal and vertical extent of the hydrocarbon product lens. Approximately 60 wells and borings have confirmed the areal extent of the lens.

3.2. SUBSURFACE OCCURRENCE

Field investigations and literature evaluation of the permeability and central fault characteristics of the formation, performed by DSM, strongly suggest that the current distribution of subsurface hydrocarbon product resulted from the downward migration of spilled or released hydrocarbon product along the central fault plane to the water table, with little or no lateral migration. At the junction of the ground water table and the central fault plane, which may have been enlarged by solutioning, the hydrocarbon product accumulated or mounded over time. The accumulated product, driven by its positive head pressure, then infiltrated into the surrounding formation. This supposition is supported by data collected during the interim product recovery operations at the CORCO facility. Specifically, a large volume of product (2,730,000 gallons) was recovered by intermittent pumping from only two Interim Recovery Wells (PT-2 and PT-3), which were located in the central fault zone, during two very short periods of time (1.5 months each). Since the average transmissivity of the formation would not allow such rapid production, these recovery rates suggest that the hydrocarbon product recovered from the Interim Recovery Wells PT-2 and PT-3 was associated with the cavity produced by solutioning along the central fault plane.

Measurements of the hydrocarbon product plume started in 1994 and continued through November 1997. The measurements in the wells do not exhibit large differences from one measurement event to the next, with the exception of the measurements taken in PD-25, and PD-10 which are located in the central fault zone (DSM 1994). **Appendix A – Hydrocarbon Product Thickness In The Formation** presents a summary of the product thickness in the formation since measurements began. A plot of the most recent data, the November 1997 measurements, indicates that the zone of thickest hydrocarbon product is generally along the trend of the central fault. This distribution is consistent with the theory of product accumulation and distribution presented above.

Delineation wells, PD-25 and PD-10, are the observation wells for Interim Product Recovery Wells PT-2 and PT-3 respectively. Interim Product Recovery Wells PT-2 and PT-3 are also located in the central fault zone. Hydrocarbon product thickness measured in these wells is representative of the thickness of product in the central fault zone. The hydrocarbon product thickness that was measured in monitoring wells PD-25 and PD-10 declined very rapidly as product was pumped from the associated PT-2 and PT-3 recovery wells during the first two quarters of 1997. From May 1997 to November 1997 an increase in product thickness in the wells from 1.65 ft to 2.88 ft. was measured. Additional information regarding the Interim Product Recovery operations from Wells PT-2 and PT-3 is provided in this section. A comparison of the fluctuation of hydrocarbon product thickness from the first measurement, through the period of pumping from the central fault, is presented in **Table 1 – COMPARISON OF MEASURED PRODUCT THICKNESS IN PD-10 AND PD-25**.

Table 1 – COMPARISON OF MEASURED PRODUCT THICKNESS IN PD-10 AND PD-25

Well Number	Date of Measurement			
	September 1994 (feet)	November 1995 (feet)	May 1997 (feet)	November 1997 (feet)
PD-10	10.23	8.26	2.17	3.82
PD-25	9.20	6.34	2.10	4.98

The final delineation of the hydrocarbon product in the subsurface was completed in September 1997 and presented in the *Phase II – Letter Report – Findings of the Off-Property Subsurface Product Delineation Program* (DSM 1998). Again, the limits of the hydrocarbon product plume were essentially the same as shown in previous years. These measurements indicate that the hydrocarbon product has not moved substantially in any direction over a period of at least three (3) years. It is further speculated that the CORCO removal of the accumulated subsurface product from the solution cavity associated with the central fault plane has removed the positive product head pressure to the formation and has decreased infiltration of product to the surrounding formation.

Recovery wells, PT-2 and PT-3, which were installed along the central fault trace, (**Figure 1 – Monitoring Well Location Plan**) produced approximately 65,000 barrels (2.7 million gallons) of hydrocarbon product over approximately a nine-month period using electric, submersible, water well pumps. The majority of this hydrocarbon product was recovered in two pumping events each of which lasted approximately one and one-half (1½) months each. The time limiting factor for these pumping events was the available storage at the facility for the hydrocarbon product. After completion of the second major pumping event, attempts to continue hydrocarbon product recovery, without associated ground water recovery, have been proved to be unsuccessful with the water well pumps. However, from the time of the measurement of hydrocarbon product thickness in the wells in May 1997, shortly after pumping stopped, until the subsequent measurement in November 1997, the thickness of the hydrocarbon product in the wells had increased by only 1.5 to 3.0 feet. If there was another source of hydrocarbon product recharge, that is, an area connected by a higher permeability zone to the central fault zone that contained a substantial amount of hydrocarbon product, these wells should have recharged to their pre-pumping levels in a shorter period of time. Measurements and calculations performed in November 1997 are a further indication that the major source of hydrocarbon product was removed. Therefore, since the driving head has apparently been removed from the source, no measurable, lateral expansion of the hydrocarbon plume is expected in the near future.

As stated above, **Figure 2 – Extent of Hydrocarbon Product**, represents the horizontal and vertical extent of the hydrocarbon product lens based on the November 1997 measurement of the wells. The maximum, calculated thickness in the formation is approximately two (2) feet, near the center of the lens, and it thins toward the edges (Blake and Hall, 1984). No estimate has been made for the capillary fringe of product because it has not been possible to collect data from the capillary fringe during drilling operations. Attempts were made to core through the hydrocarbon product zone; but,

because of the friable nature of the material, adequate core recovery was not possible (DSM 1996). The basis and calculations for the hydrocarbon product thickness in the formation are presented in **Appendix A – Hydrocarbon Product Thickness In The Formation**. In two areas, one in the western area and one in the eastern area, there is no product in the delineation wells (**Figure 2**). Although the exact reason for the non-occurrence of product is not known, it is presumed to be due to a change in the geology of the area or a structural feature, such as a fault, that prevented the encroachment of the product.

4. MODEL SELECTION

The objective of the next phase of the subsurface remediation of the facility is to recover only the hydrocarbon product and very little or, preferably, no ground water because there currently are no treatment facilities available. In addition, by removing the hydrocarbon product the source of any possible ground water contamination is eliminated. The purpose for modeling the hydrocarbon product recovery is to evaluate the performance of different product recovery scenarios and select an appropriate product recovery scenario to optimize the recovery of subsurface product from the ground water underlying the CORCO facility.

Based on the limited extent and the relatively simple distribution pattern of the hydrocarbon product lens, an analytical, two-dimensional, single-layer model was chosen. The computer model that was selected is the “WinFlow” modeling software produced by Environmental Solutions, Inc., located in Herndon, Virginia. The WinFlow model is an interactive, analytical model that simulates two-dimensional steady state and transient ground water flow. The steady state module simulates ground water flow in a horizontal plane using analytical functions developed by Strack (1989). The transient module uses equations developed by Theis (1935) and Hantush and Jacob (1955) for confined and leaky aquifers. Each of the modules of the model uses the basic assumption that the aquifer is infinite, homogeneous, isotropic, has a single layer, and contains a uniform gradient. Various parameters within the model can be varied to calibrate the model to an existing, real condition. WinFlow has been tested and verified against the USGS MODFLOW model and is considered an “EPA approved” model.

Other, more complex, models such as finite difference and finite element models were considered; but, because of the inhomogeneities of the formation and the lack of data to define them precisely, they could not have been expected to generate more credible results than the model that was chosen.

5. RECOVERY MODELING DATA AND ASSUMPTIONS

5.1. RECOVERY MODELING DATA

In the development of the recovery model for the CORCO facility, the steady-state module of the WinFlow model was applied because, at the CORCO facility, the

subsurface hydrocarbon product is in an unconfined condition and the steady-state module is the appropriate choice for an unconfined condition.

Previous hydraulic conductivity tests (slug tests) conducted in various delineation wells at the facility did not generate data that differentiated between the hydraulic conductivity of the hydrocarbon product and the ground water and, therefore, was not suitable for this modeling effort (DSM, 1996). To design a model that represents only hydrocarbon product recovery it is necessary to determine what the hydraulic properties of the hydrocarbon properties are, independent of the ground water. In November 1997, recovery tests were performed in two (2) wells (EPRB-3 and EPRB-6) that were installed specifically for the purpose of determining a hydraulic conductivity of the hydrocarbon product that is representative of the majority of the formation for use in simulating its recovery in the computer model. In the two (2) test wells, the entire column of liquid, both hydrocarbon product and ground water, was removed and allowed to recover from the formation. Measurement of the rate of recovery for both the hydrocarbon product and ground water was recorded and utilized in the simulations. Graphs of the data from these test results are presented in **Appendix B – Ground Water and Hydrocarbon Product Recovery Rate for EPRB-3 and EPRB-6.**

In these tests, the surface of the hydrocarbon product recovered very rapidly to its pre-test elevation, but the thickness of the hydrocarbon product in the well was slightly greater than before the pumping. The ground water recovered at a slower rate and, as it did, it displaced the hydrocarbon product back into the formation. This behavior indicates that, as the hydrocarbon product is removed, ground water will rise in the well. If the product is removed too quickly, ground water will rise rapidly into the well displacing the product, greatly reduce the ability to remove product and destroy the effectiveness of the well.

For this simulation, the capillary fringe effect of the product and the ground water has been ignored. The well depths necessary to reach the hydrocarbon product/ground water zone and formation conditions that preclude coring of the saturated zone have not allowed for the collection of data on the extent of the capillary fringe. In practice, it is assumed that whatever product is available will drain from the fringe under gravitational forces and the remainder will be bound in the formation, after remediation, until such time as it is naturally degraded.

An analysis of the recovery data was made using the analytical computer program "Aqtesolv for Windows" (Geraghty and Miller, 1995). The program automatically analyzes data from time of maximum displacement until the time that equilibrium is approached, using the Bouwer and Rice (1976) method of slug test analysis. This early time analysis indicates that the measurements represent the hydraulic conductivity for the hydrocarbon product in the well pack. A summary of the analysis of the data is presented in **Table 2 – HYDRAULIC CONDUCTIVITY COMPARISONS.** EPRB-3 exhibited the lowest hydraulic conductivity of the two (2) wells tested. The early time hydraulic conductivity was calculated to be 1.5×10^{-3} cm/sec (3×10^{-3} ft/min). Analysis of the later recovery data, as equilibrium is approached, yields a hydraulic conductivity of 3.6×10^{-7} cm/sec

(7.06×10^{-7} ft/min), which is four (4) orders of magnitude less than the initial, or early time, results, but is more representative of the formation response to the pumping. The test that was performed in EPRB-6 yielded similar results. Both of these test results agree with the published data on the hydraulic conductivity of this type of formation (Driscoll, 1987). The early time results that represent the response of the well's gravel pack, are not indicative of the formation response and, therefore were not used in the final analysis and modeling. These results are consistent with the observed performance of existing hydrocarbon product recovery wells at the CORCO facility, in the Ponce Limestone. The initial recovery rates are high, but as the column of hydrocarbon product in the well is reduced, the sustainable pumping rate decreases rapidly. The recovery tests indicate that the hydraulic conductivity of the formation is generally on the order of 1×10^{-5} cm/sec (4.7×10^{-4} ft/day) for the hydrocarbon product. These results are in general agreement with values described in available geological literature (Grossman, et.al., 1972). The analyses of the recovery tests are presented in **Appendix C – Hydrocarbon Product Recovery Test Analyses**.

Table 2 – HYDRAULIC CONDUCTIVITY COMPARISONS

WELL NUMBER	HYDRAULIC CONDUCTIVITY (cm/sec)	HYDRAULIC CONDUCTIVITY (cm/sec)
EPRB – 3	1.5×10^{-5}	3.6×10^{-7}
EPRB – 6	2.9×10^{-4}	3.0×10^{-5}

The hydraulic conductivity recovery tests also indicate that the hydrocarbon product will have a low (generally less than 1 gpm) sustained pumping rate because of the reduction in the transmissivity as the hydrocarbon product is removed. The exception would be in instances where production is from a secondary permeability feature such a fault. The transmissivity of a formation is the parameter that determines how much fluid is recoverable from a formation and at what pumping rate. Transmissivity is the ability of the formation to produce a fluid. It is defined as the rate of flow, in gallons per minute, through the vertical section of an aquifer one foot wide and extending the full saturated height of the aquifer under a hydraulic gradient of one (1) (Theis, 1935). In an unconfined condition, as the fluid is removed from the matrix of the formation, the saturated thickness of the formation decreases. This lowers the transmissivity and, therefore, decreases the ability of the aquifer to produce fluid. Therefore, the sustainable pumping rate decreases dramatically. This condition is exacerbated even more when the original saturated thickness is small, like the hydrocarbon product thickness that is found in the CORCO facility. The thin (approximately one to two feet thick) hydrocarbon product thickness layer will severely limit the pumping rate of individual wells in the recovery system.

5.2. RECOVERY MODEL CALIBRATION

Based on the above assumptions, observations and calculations, the WinFlow model was constructed to approximate actual field conditions as follows:

1. The area of the hydrocarbon product lens is assumed to act as an unconfined, limited extent aquifer.
2. The bottom of the hydrocarbon product lens is the top of the water table; which, for simulation purposes, is considered the impermeable bottom of the hydrocarbon product "aquifer".
3. A continuous line sink with zero head represents the edges of the hydrocarbon product lens.
4. The reference head required by the model was placed inside of the lens area so that the model could not "see" beyond the zero head, line sink boundary.
5. Two "ponds", with zero heads in them, represent the zero thickness areas within the lens.
6. Manipulating the variable parameters within calculated and reasonable limits was done so that the base model generally reproduced the known contours of the lens.

These assumptions were entered into the model and calibration runs were begun to refine the base model until it resembled the measured field conditions. The calibration runs consisted of varying the parameters in the above assumptions within measured and reasonable limits based on experience of the modeler. The final model calibration parameters are listed in **Appendix D – Model Calibration Parameters** and the pre-recovery simulation is presented in **Figure 3 – Simulated Hydrocarbon Product Distribution, Before Remediation**.

6. PRODUCT RECOVERY SIMULATION

6.1. RECOVERY WELL DISTRIBUTION

Once the base model of the system was completed, simulated extraction of hydrocarbon product was begun. Various numbers of wells were placed at various locations within the body of the product lens and the pumping rates were varied until there was a decrease in the head values (thickness) of the product lens. The model indicates that continuous pumping of as few as ten wells could substantially reduce the product lens. However, the model assumes that the formation is a homogeneous, perfectly responding aquifer. In reality, as shown by numerous borings and hydraulic conductivity testing, the formation is quite heterogeneous in nature. In addition, the response of the formation to previous recovery testing efforts in the two (2) recovery test wells indicates that the recharge to any one well will be very slow. Therefore, from a practical point of view, a series of wells evenly distributed over the hydrocarbon product lens will be more successful at removing the greatest amount of product in the shortest time. Simulations were run for systems with 10 wells, 25 wells, and 35 wells (**Figures 4, 5, and 6, Simulated Hydrocarbon Product Distribution, After Remediation**). All of the wells in each scenario were modeled as 6-inches in diameter and pumping at one quarter of a gallon per minute (1/4 gpm). The most effective reduction of product was predicted in the simulation that used the 35, evenly distributed wells (**Figure 6**).

6.2. HYDROCARBON PRODUCT RECOVERY

The model indicates that it is possible to remediate the hydrocarbon product in the subsurface at the CORCO facility. However, as stated above, the WinFlow model simulates conditions at steady state. In order to achieve the remediation level at steady state indicated by the model, the model assumes a perfectly responding formation and the ability to pump hydrocarbon product at a continuous rate 24 hours a day, 365 days per year. It does not indicate the total elapsed time required to reach the steady state condition.

In practice, the inhomogeneities in the formation will require a continuing program of observation and adjustment during the operation of the recovery system. All of the wells may not be able to produce continuously at a fixed rate because of the reduction of transmissivity in the formation as the product is removed. Also, the maintenance of the system will reduce the amount of operational time available to any one well or group of wells. Installing this large number (35) of production wells will counterbalance some of the lost production caused by the reduction in transmissivity in the vicinity of any particular well and, by pumping a larger number of wells at a lower rate, more volume of hydrocarbon product should be recovered.

Continual monitoring, analysis, and simulation of the results of the remediation effort over the period of performance will allow predictions to be made for the recoverable amount of hydrocarbon product, the elapsed time to complete the recovery, and possibly, to predict the rate of decay of the remainder of the hydrocarbon product in the formation.

7. MODEL VERIFICATION

As a quality assurance check a third party was selected to review the calibration and simulation of the hydrocarbon recovery. Dr. Michael Voorhees, President of E H SYSTEMS, INC., was selected to verify the construction and calibration of the WinFlow model simulation. He concluded that the WinFlow model was correctly applied and that the parameters used in the simulation were reasonable assumptions, based on the data provided to him and his understanding of the hydrogeology of the facility. These parameters were found to be appropriate for this site when single-phase gasoline flow was modeled.

As a further check, Dr. Voorhees reviewed the assumptions and model calibration against his self-developed, analytical code, GLOREFLOW (Gasoline Liquid Optimum Recovery Evaluation). The model assumes isotropic, steady state, isothermal, two dimensional ground water flow. GLOREFLOW includes the effects of density, viscosity, temperature (for the thermodynamic properties), as well as surface tension. Hydrocarbon product degradation (first-order decay), porosity, and mass balance were included in the analysis performed by GLOREFLOW.

Degradation is very important at this site if clean-up time frames are to be of reasonable duration. Executing GLOREFLOW with default parameters included in the source code, clean-up times are on the order of a decade. Therefore, estimates of first-order decay coefficients should be pursued diligently as degradation is critical to cleanup.

The GLOREFLOW model is a very conservative model. Results from this model indicate that approximately 38 wells may be required due to the low hydraulic conductivity of the site and allowable pumping rates per well are quite small. In addition, the recovery time predicted by this model is approximately ten (10) years. However, because the model is conservative, this time prediction probably overestimates the actual time required.

The basis for the GLOREFLOW model and the model code are presented in **Appendix E – Model Verification**.

8. CONCLUSIONS

The computer simulation of the recovery of hydrocarbon product from the Ponce Limestone within the CORCO facility boundaries indicates that it is legitimate to expect a successful recovery of a large portion of the subsurface hydrocarbon product, although the model does not establish the precise percentage of recovery. It also demonstrates that it should be possible to achieve this recovery using conventional pumping equipment and wells.

In order to achieve maximum effectiveness, it will be necessary to pump from approximately 35 wells, evenly distributed over the area of the hydrocarbon product lens. Pumping from these wells at a low rate, over an extended period of time, will substantially reduce the volume of the hydrocarbon product in the formation without damaging the ability of the formation to yield the hydrocarbon product or produce a substantial amount of ground water.

Calculations of the current amount of hydrocarbon product in the formation indicate approximately 18 million gallons are contained in the product plume (DSM 1997). Utilizing the conservative assumption that between 30 and 40 percent of the hydrocarbon product is recoverable, approximately 5.4 to 7.2 million gallons of recovered product could be produced during the remediation efforts. Ionic bonding of the hydrocarbon product to the soil grains, the low hydraulic conductivity of the formation, and variability in the transmissivity of the formation were considered in the assumption of percent hydrocarbon recovery. At a pumping rate of one quarter of a gallon per minute from the 35 wells, a straight, volumetric calculation of the amount of time required to produce the recoverable percent of the total estimated volume of subsurface product yields approximately 1.7 to 2.3 years. The time estimate calculation is based on a perfectly homogenous formation and the continual operation of all of the wells on a 20-hour per day, 300 days per year basis. The verification model, GLOREFLOW, is more sensitive to the variable parameters of density, viscosity, surface tension, and natural decay of the hydrocarbon product in the formation and therefore is a much more conservative predictor of the amount of time necessary to remove the available product from the formation. GLOREFLOW predicts that approximately the same number of wells evenly distributed over the hydrocarbon product plume will recover the available product in a much longer period of time, approximately 19 years. However, the recovery time to cleanup includes the decay phase of the remediation. The actual time required to recover only the liquid phase of the hydrocarbon product will likely be much shorter. The same model, without the decay phase indicates approximately 10 years for product recovery.

The actual time necessary for recovery of the available hydrocarbon product is probably somewhere between the two estimates.

Degradation should be addressed by several synoptic measurements of product thickness at the site to determine the change in volume of the plume with time. If all hydrocarbon product sources have been eliminated and the volume recovered is accounted for, the in-place volume should decrease with time due to natural degradation. Measurement of the volume change of the hydrocarbon product with time will enable the determination of the in-place half-life due to degradation. One approach to use for the statistical analysis of data is kriging. Kriging the operational data on product recovery and remaining thickness should determine the remaining volume quite quickly. Once the degradation rate has been established by these volume measurements, recovery times can be adjusted to account for the reduction of hydrocarbon product volume (mass) with time.

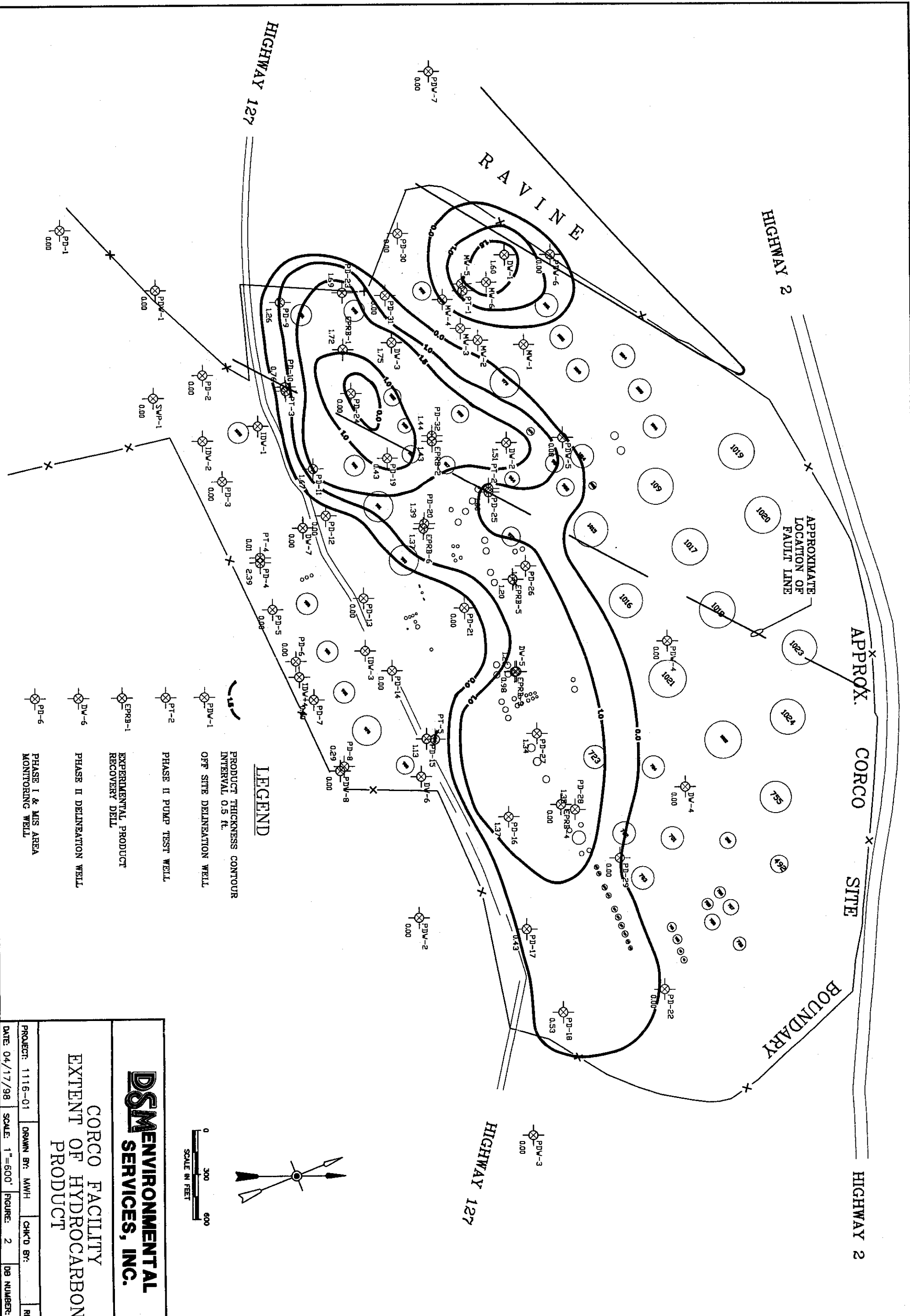
Continual monitoring, analysis, and simulation of the response of the hydrocarbon product lens to remediation efforts will allow more accurate predictions of the time required to recover the available hydrocarbon product and the rate of decay of the remainder of the hydrocarbon product in the formation.

9. REFERENCES

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9. REFERENCES

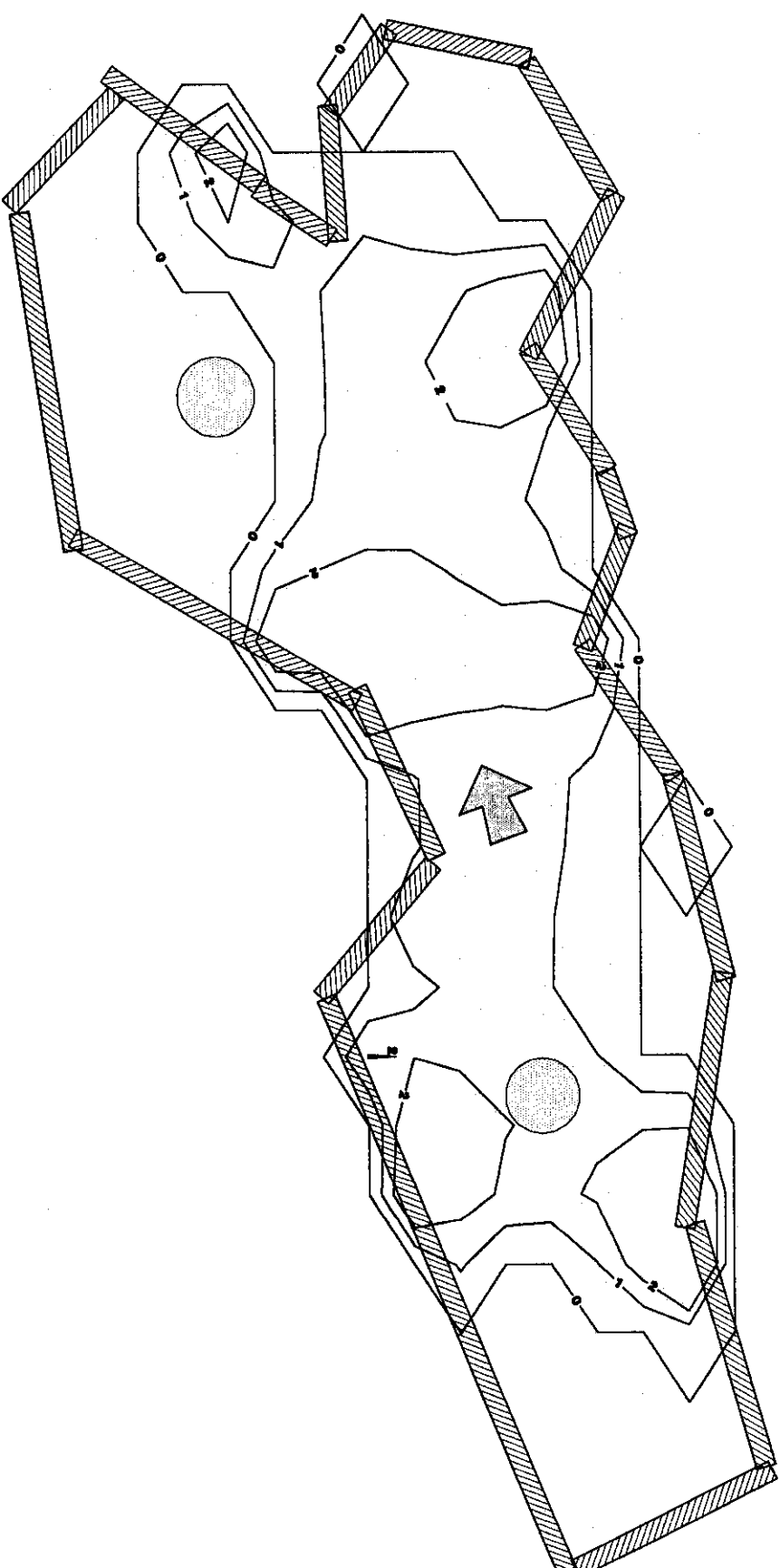
- Charbeneau, R. J. and Chen Y. Chiang, 1995, *Estimation of free-hydrocarbon recovery from dual-pump systems*, Ground Water, Vol. 33, No. 4, pp. 627 – 634.
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- Strack, O. D. L., 1989, *Groundwater Mechanics*, Prentice Hall, Englewood Cliffs, New Jersey, 732 p.
- Theis, C. V., 1935, *The relation between the lowering of the piezometric surface and the rate and duration of discharge of a well using groundwater storage*, Trans. American Geophysical Union, Vol. 16, pp. 519 – 524.



DSM ENVIRONMENTAL SERVICES, INC.


CORCO FACILITY
EXTENT OF HYDROCARBON
PRODUCT

PROJECT: 1116-01	DRAWN BY: MWH	CHK'D BY:	REV:
DATE: 04/17/98	SCALE: 1"=600'	FIGURE: 2	DB NUMBER:



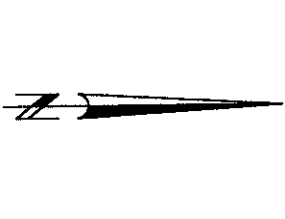
LEGEND

 HYDROCARBON PRODUCT THICKNESS
CONTOUR INTERVAL 1 ft.

 AREA OF NO HYDROCARBON PRODUCT

 MODEL REFERENCE HEAD

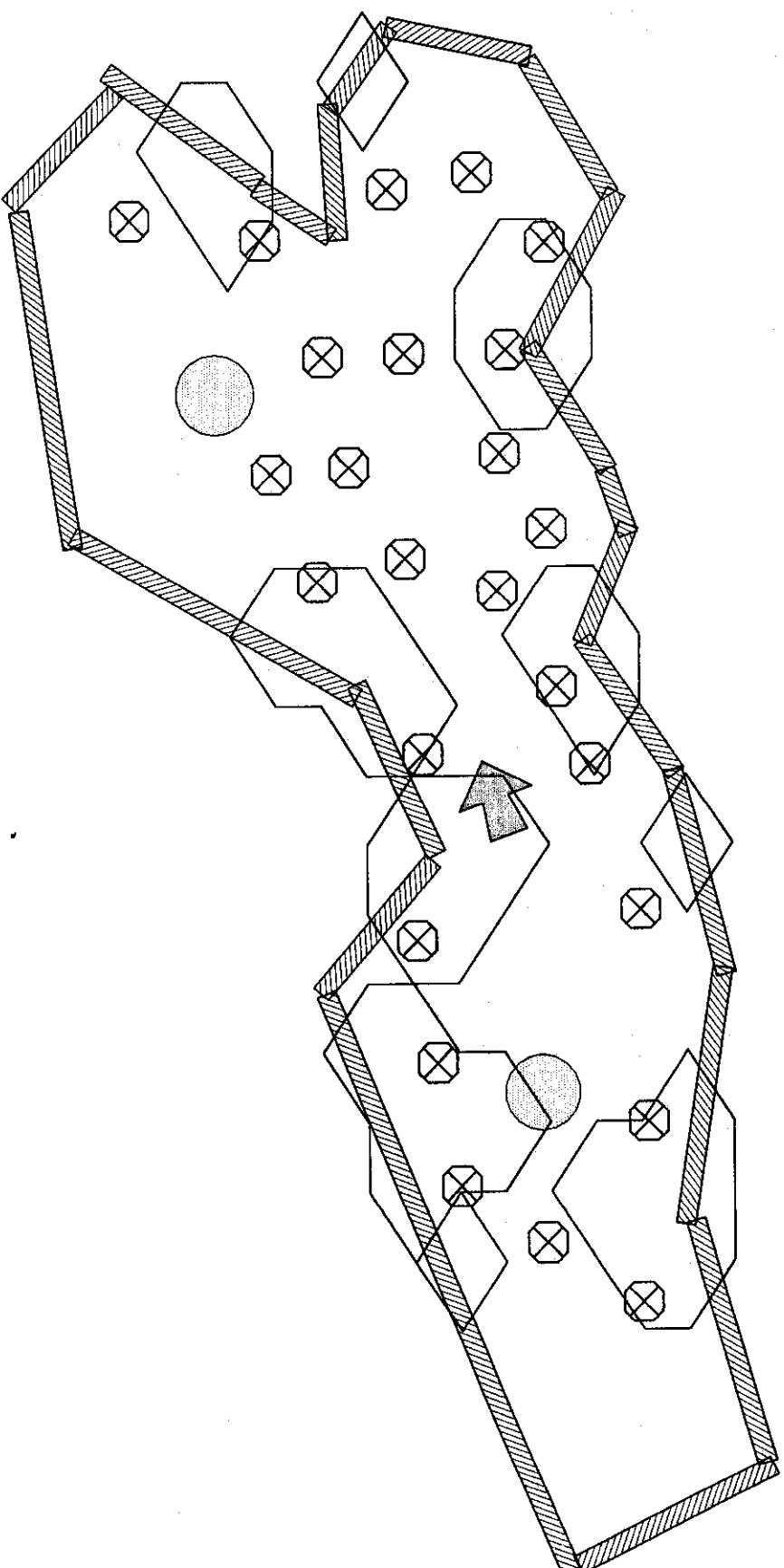
 MODEL BOUNDARY








**DSM ENVIRONMENTAL
SERVICES, INC.**

CORCO FACILITY
SIMULATED HYDROCARBON PRODUCT
DISTRIBUTION BEFORE REMEDIATION

PROJECT: 1116-1	DRAWN BY: MWH	CHK'D BY: CRG	REV:
DATE: 04/24/98	SCALE: AS NOTED	FIGURE: 3	DS NUMBER:



LEGEND

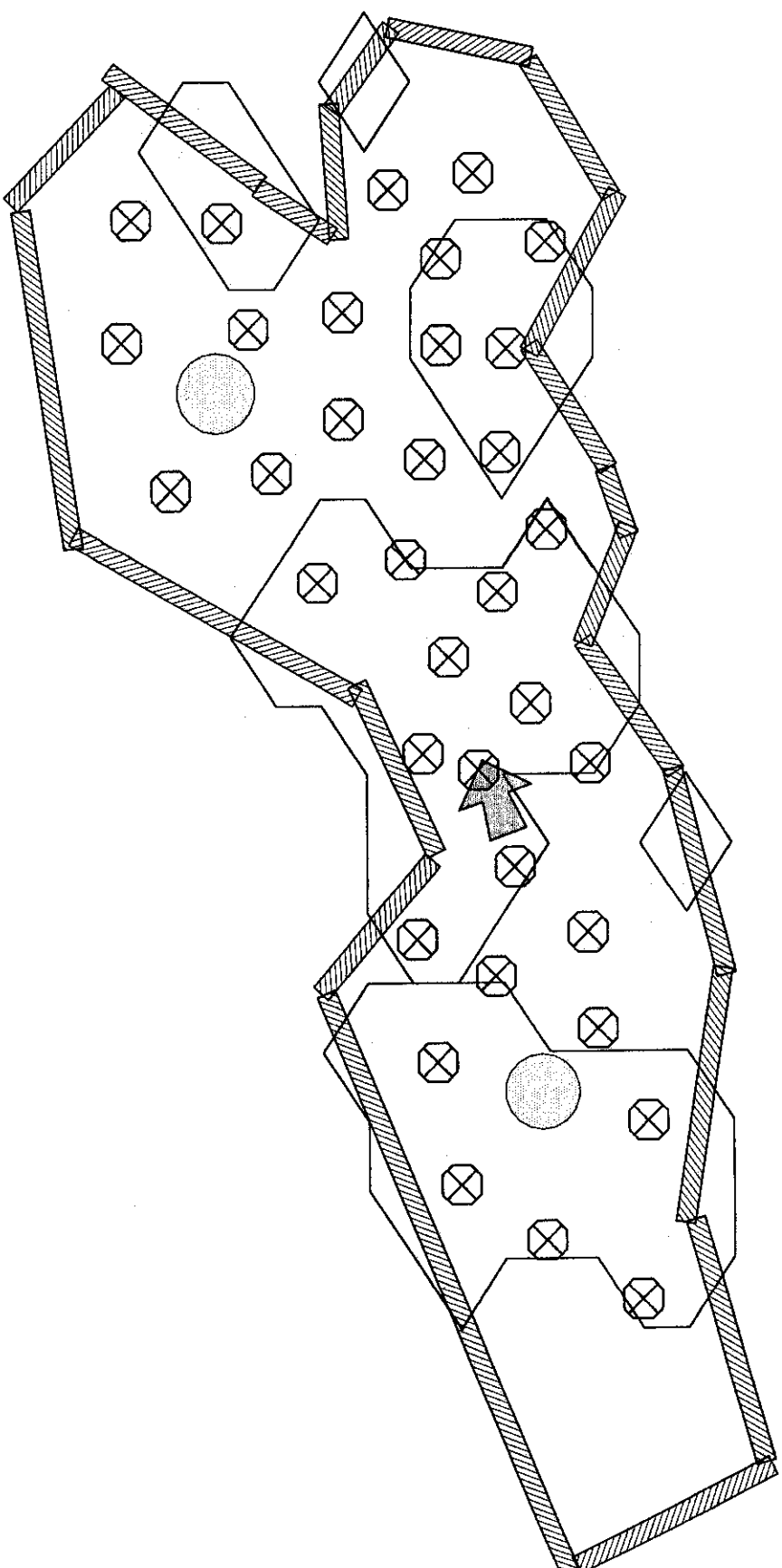
-  HYDROCARBON PRODUCT THICKNESS
CONTOUR INTERVAL 0.25 ft.
-  AREA OF NO HYDROCARBON PRODUCT
-  MODEL REFERENCE HEAD
-  MODEL BOUNDARY
-  HYDROCARBON PRODUCT
RECOVERY WELL

**DSM ENVIRONMENTAL
SERVICES, INC.**

CORCO FACILITY
SIMULATED HYDROCARBON PRODUCT
DISTRIBUTION AFTER REMEDIATION
25 WELLS PUMPING 0.25 GPM


PROJECT: 1116-1	DRAWN BY: MWH	CHK'D BY: CRG	REV:
DATE: 04/24/98	SCALE: AS NOTED	FIGURE: 5	DS NUMBER:


0 100 200
SCALE IN METERS




LEGEND

 HYDROCARBON PRODUCT THICKNESS
CONTOUR INTERVAL 0.25 ft.

 AREA OF NO HYDROCARBON PRODUCT

 MODEL REFERENCE HEAD

 MODEL BOUNDARY

 HYDROCARBON PRODUCT
RECOVERY WELL

**DSM ENVIRONMENTAL
SERVICES, INC.**

CORCO FACILITY

SIMULATED HYDROCARBON PRODUCT
DISTRIBUTION AFTER REMEDIATION
35 WELLS PUMPING 0.25 GPM

PROJECT: 1116-1	DRAWN BY: MWH	CHKD BY: CRG	REV:
DATE: 04/24/98	SCALE: AS NOTED	FIGURE: 6	DS NUMBER:

APPENDIX A

**HYDROCARBON PRODUCT THICKNESS IN THE
FORMATION**

Appendix A

**APPENDIX A.
HYDROCARBON PRODUCT THICKNESS
in the
FORMATION**

Well Number	Date of Measurement			
	Sep-94	Nov-95	May-97	Nov-97
MW-01				
MW-02				
MW-03	1.73		Pump in well	Pump in well
MW-04	1.39		Pump in well	Pump in well
MW-05	2.04		Pump in well	Pump in well
MW-06	1.60		Pump in well	Pump in well
PD-1				
PD-2				
PD-3				
PD-4	2.41	3.84	2.05	2.39
PD-5				
PD-6				
PD-7				
PD-8			0.01	0.29
PD-9	1.94	1.93	1.36	1.26
PD-10	2.05	2.04	0.43	0.76
PD-11	2.06	2.14	1.59	1.67
PD-12				
PD-13				
PD-14	0.13	0.02	0.05	
PD-15	1.82	1.19	1.42	1.13
PD-16	1.52	1.58	0.55	1.37
PD-17	0.69	0.46	0.57	0.43
PD-18	0.72	0.67	0.07	0.53
PD-19				0.43
PD-20	1.67	1.73	1.62	1.39
PD-21				
PD-22				
PD-23	1.87	1.88	1.85	1.69
PD-24				
PD-25	1.84	1.55	0.42	1.00
PD-26	2.03	1.98	1.70	1.34
PD-27	1.83	1.61	1.55	1.34
PD-28	1.59	1.58	1.46	1.35
PD-29				
PD-30				
PD-31			0.01	
PD-32	1.98	1.94	1.64	1.44

Appendix A

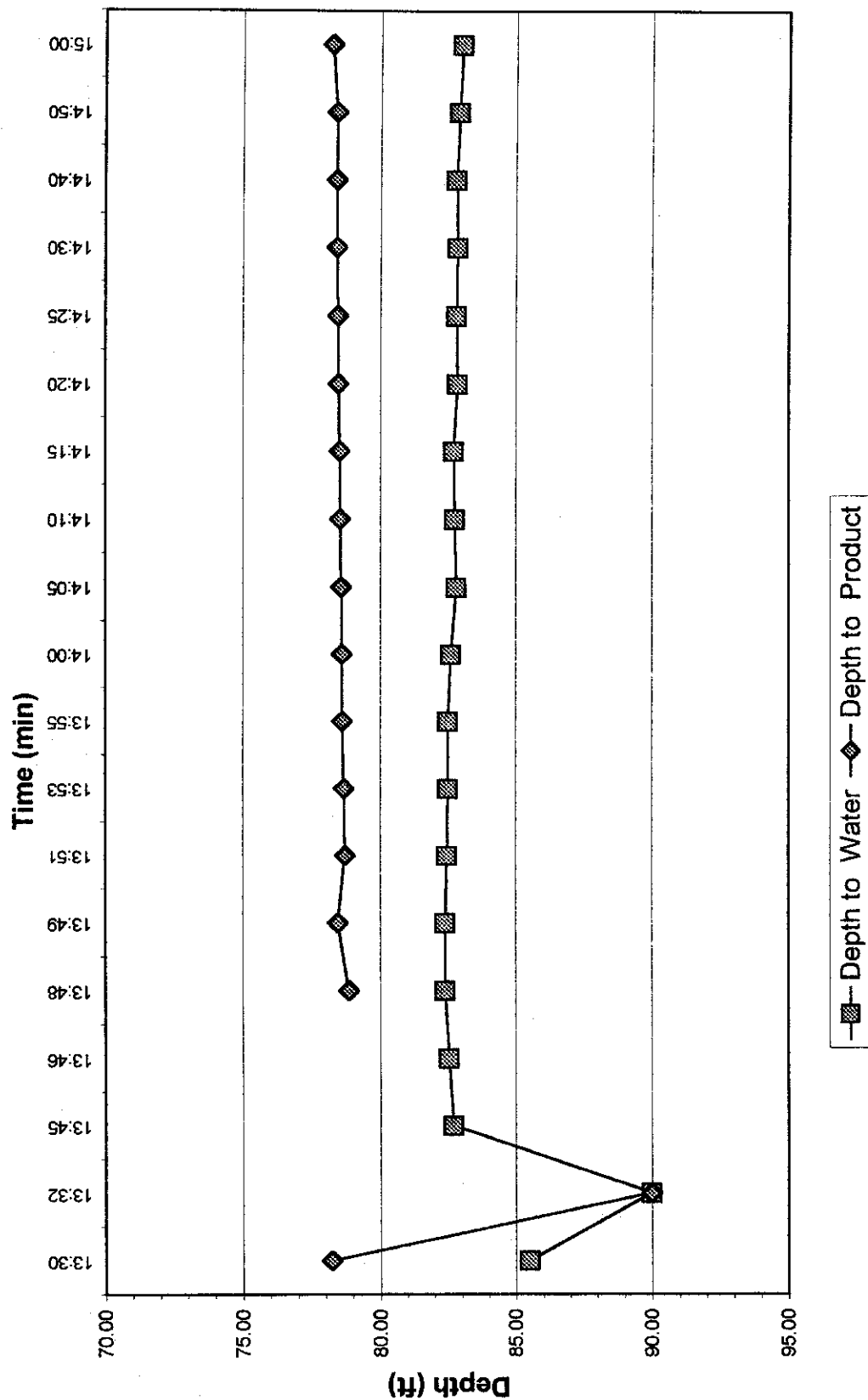
PT-1			Plugged @ 71'	Plugged @ 71'
PT-2		1.77	Pump in well	Pump in well
PT-3		1.75	Pump in well	Pump in well
PT-4		0.34	1.02	0.01
PT-5		1.81	1.64	Pump in well
DW-1		1.59	1.69	1.60
DW-2		0.13	1.39	1.51
DW-3		1.93	1.91	1.75
DW-4				
DW-5		1.75	1.51	1.26
DW-6		0.26	0.19	0.02
DW-7				
PDW-1				
PDW-2				
PDW-3				
PDW-4				
PDW-5				
PDW-6				
PDW-7				
PDW-8				
EPRB-1				1.72
EPRB-2				1.43
EPRB-3				0.98
EPRB-4				
EPRB-5				1.20
EPRB-6				1.37

Note: A blank space indicates zero thickness in the formation.

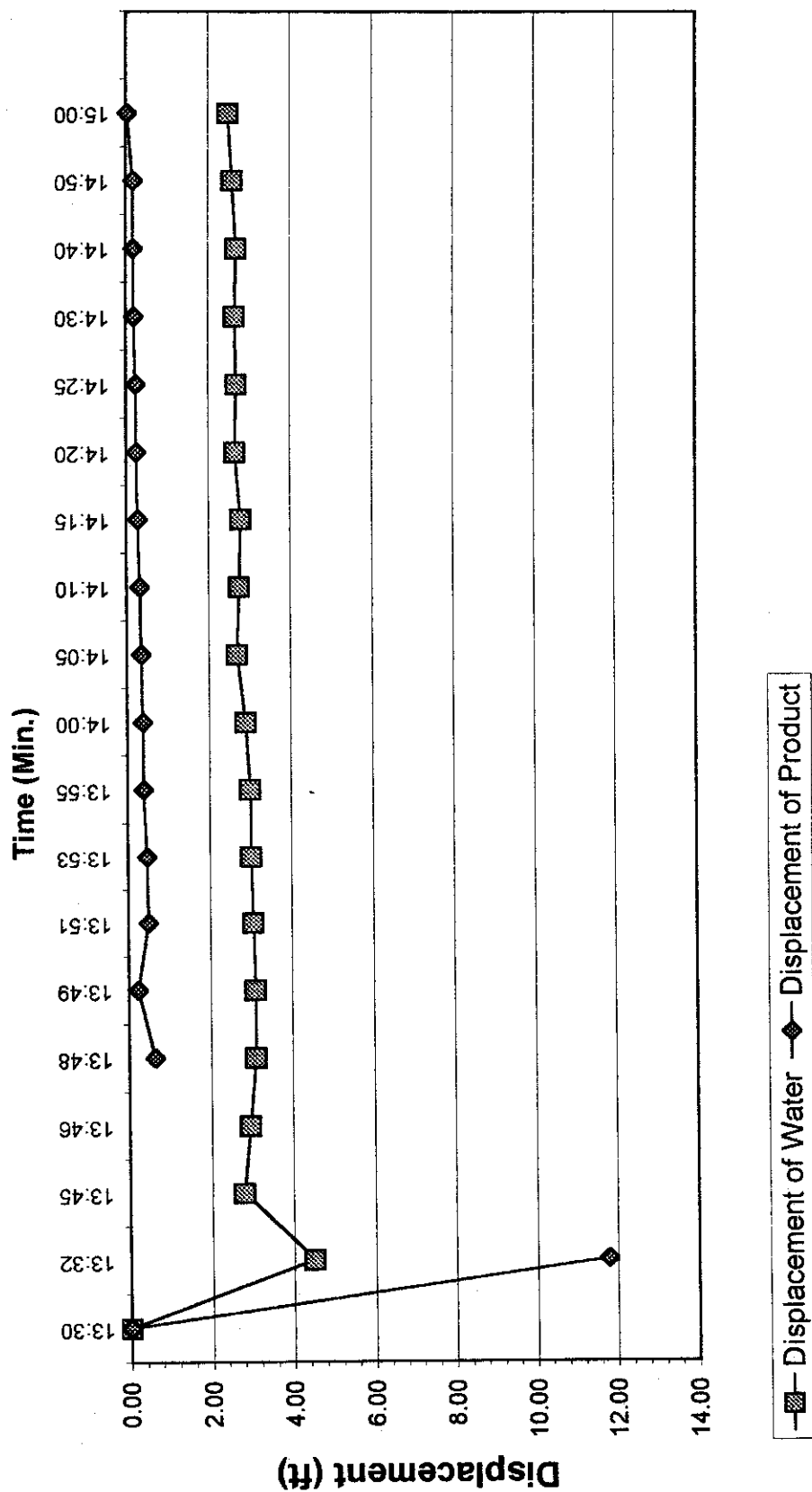
APPENDIX B

GROUND WATER AND PRODUCT RECOVERY RATE
for
EPRB-3 and EPRB-6

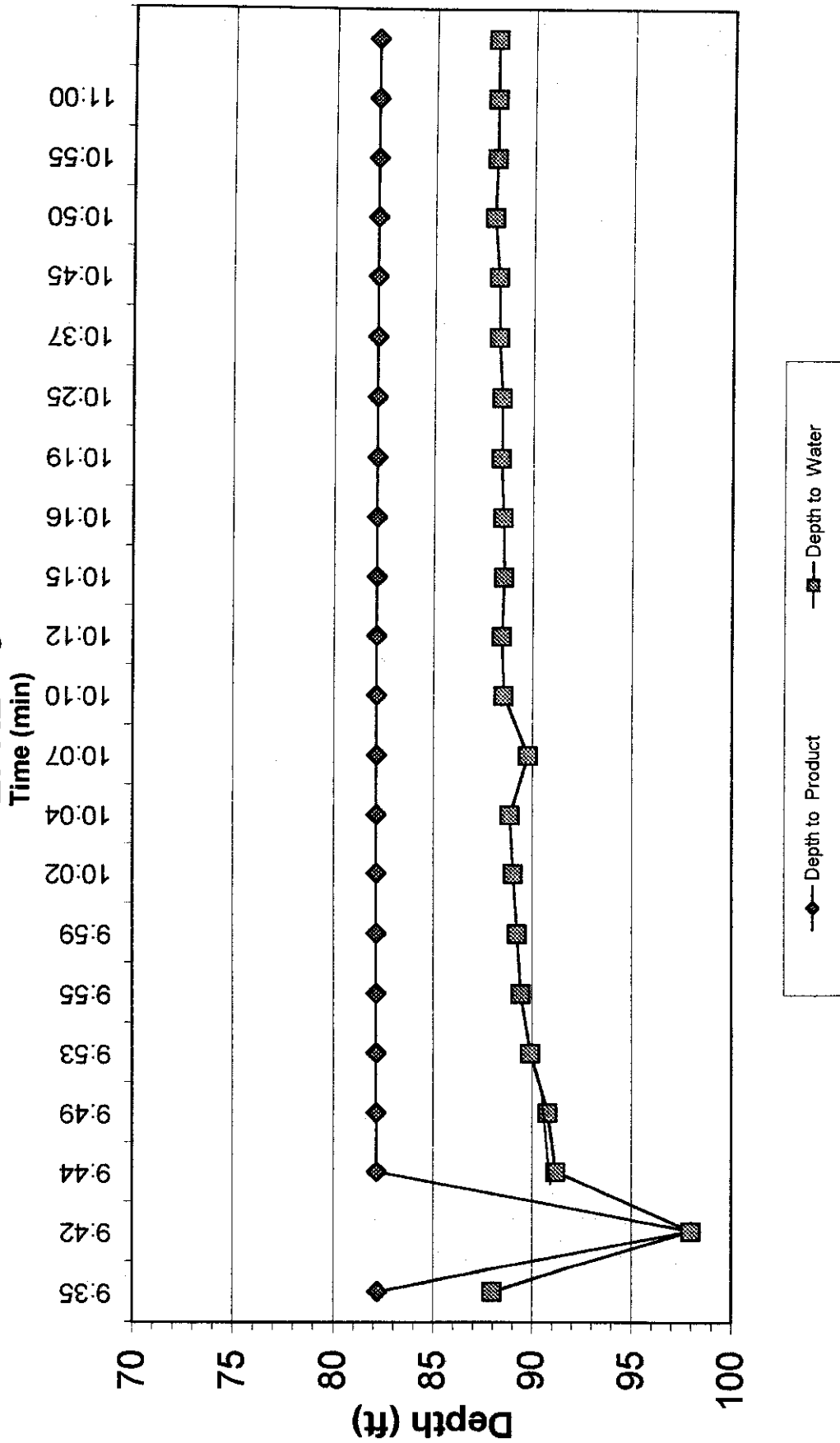
Water/Product Recovery Test EPRB-6



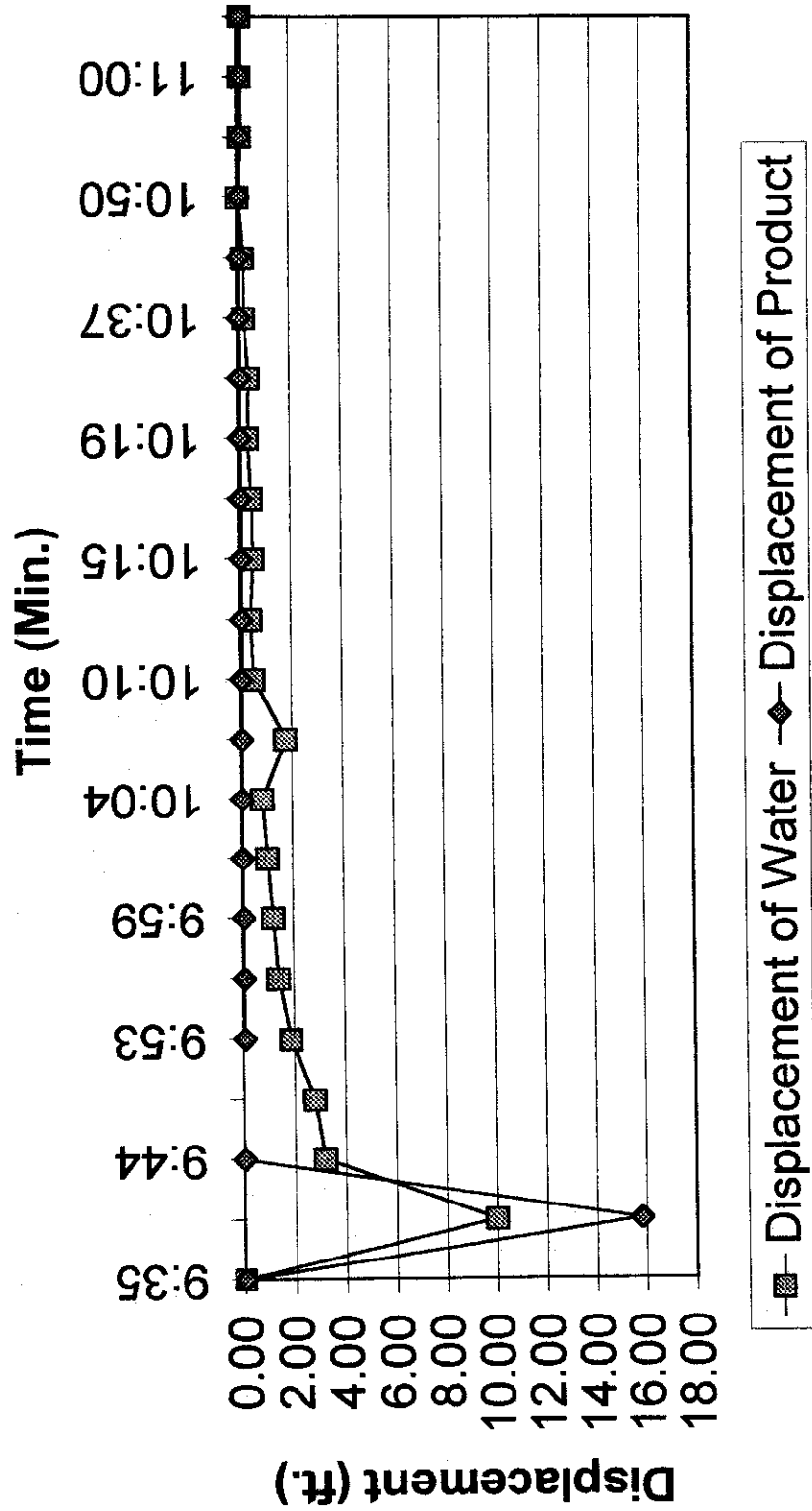
Water/Product Displacement Recovery Test EPRB-6



Water/Product Recovery Test EPRB - 3

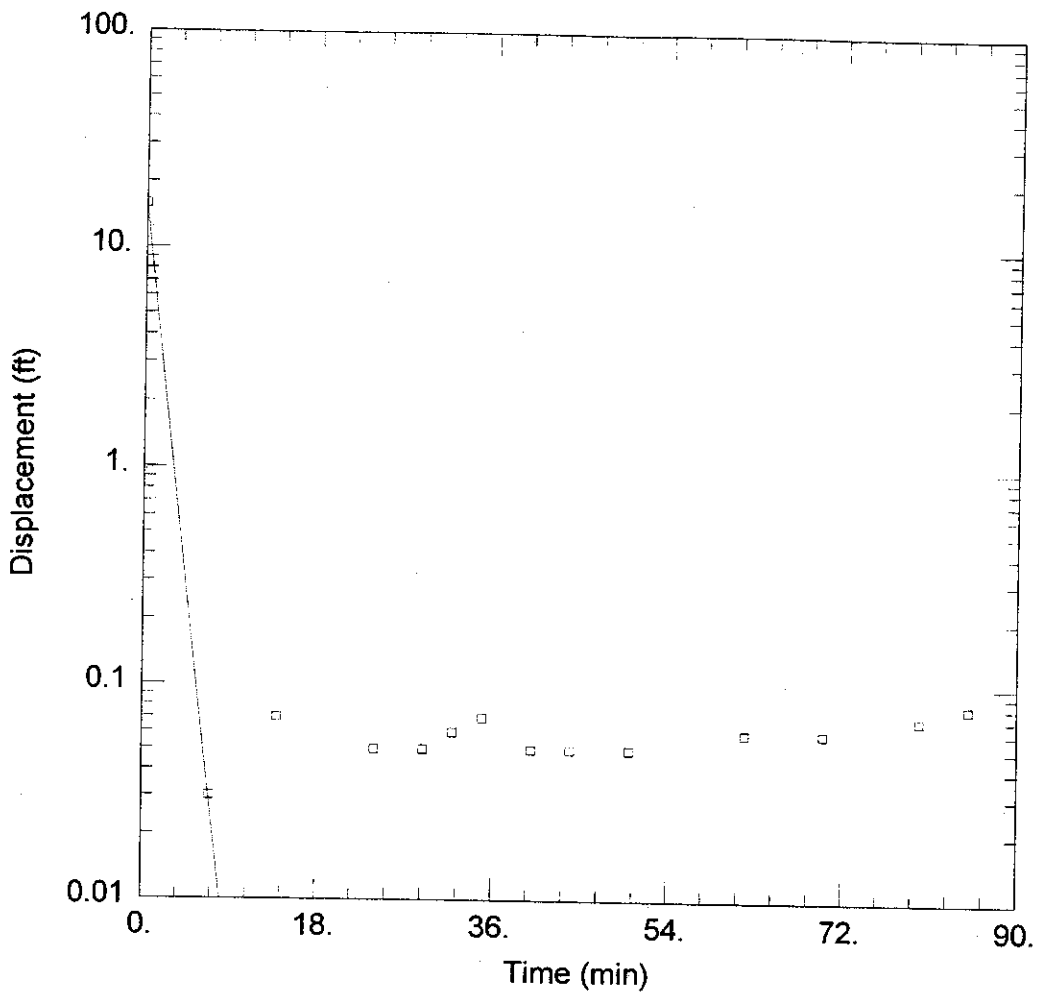


Water/Product Displacement Recovery Test EPRB - 3



APPENDIX C

HYDROCARBON PRODUCT RECOVERY TEST ANALYSIS



PRODUCT RECOVERY TEST

Data Set: G:\PROGVAQTWEPRB-3.AQT

Date: 03/23/98

Time: 13:08:16

PROJECT INFORMATION

Company: DSM

Client: CORCO

Project: 1093-01

Test Location: Puerto Rico

Test Well: EPRB-3

Test Date: 11/22/97

AQUIFER DATA

Saturated Thickness: 16. ft

WELL DATA

Initial Displacement: 16. ft

Casing Radius: 0.17 ft

Screen Length: 20. ft

Water Column Height: 16. ft

Wellbore Radius: 0.33 ft

Gravel Pack Porosity: 0.2

SOLUTION

Aquifer Model: Unconfined

Solution Method: Bouwer-Rice

K = 0.003013 ft/min

y0 = 15.81 ft

Data Set: G:\PROG\AQTMERB-3.AQT
Title: Product Recovery Test
Date: 03/23/98
Time: 13:08:22

PROJECT INFORMATION

Company: DSM
Client: CORCO
Project: 1093-01
Location: Puerto Rico
Test Date: 11/22/97
Test Well: EPRB-3

AQUIFER DATA

Saturated Thickness: 16 ft
Anisotropy Ratio (K_z/K_r): 1

OBSERVATION WELL DATA

Number of observation wells: 1

Observation Well No. 1: EPRB-3

X Location: 0 ft

Y Location: 0 ft

Observation Data

<u>Time (min)</u>	<u>Displacement (ft)</u>
0.	15.81
7.	0.03
14.	0.07
24.	0.05
29.	0.05
32.	0.06
35.	0.07
40.	0.05
44.	0.05
50.	0.05
62.	0.06
70.	0.06
80.	0.07
85.	0.08

SOLUTION

Aquifer Model: Unconfined
Solution Method: Bouwer-Rice

VISUAL ESTIMATION RESULTSEstimated Parameters

<u>Parameter</u>	<u>Estimate</u>	
K	0.003013	ft/min
y0	15.81	ft

AUTOMATIC ESTIMATION RESULTSEstimated Parameters

<u>Parameter</u>	<u>Estimate</u>	<u>Std. Error</u>	
K	0.003013	0.0009983	ft/min
y0	15.81	0.06082	ft

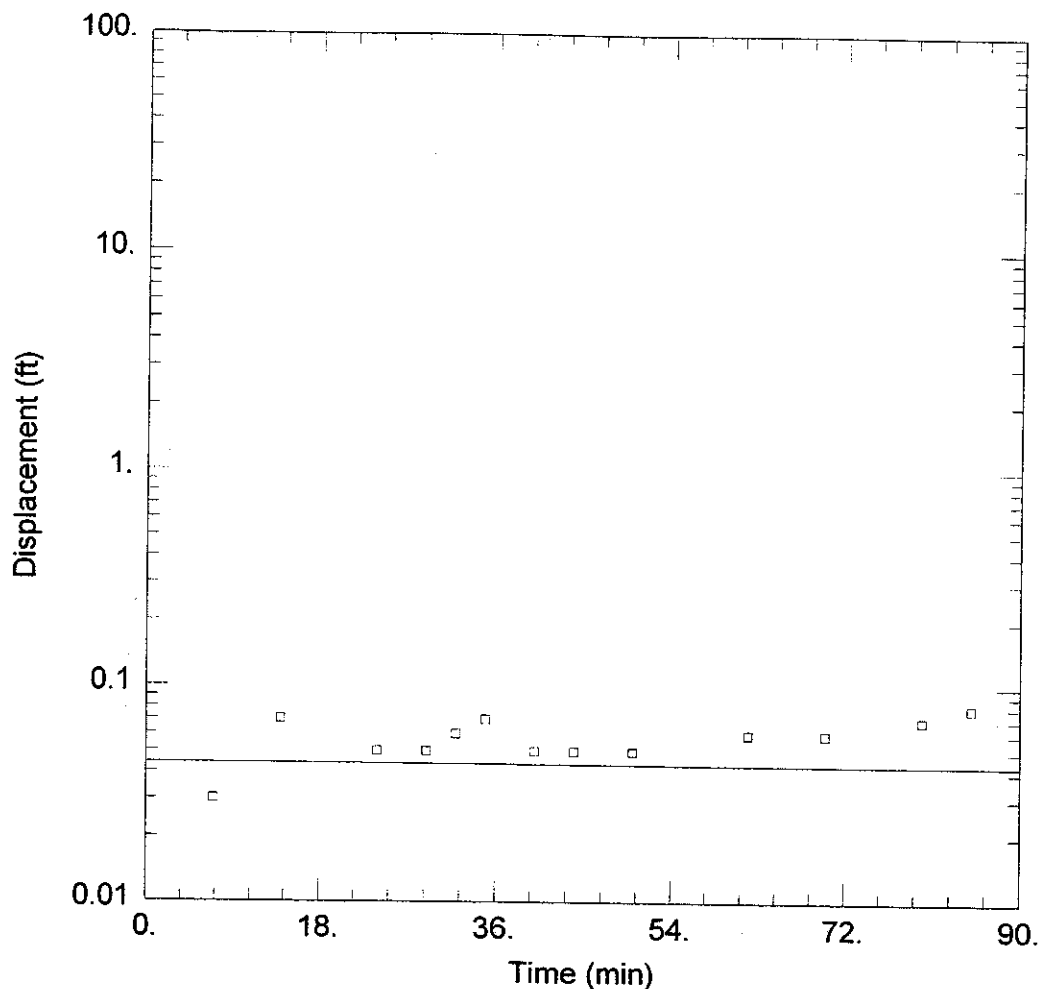
Parameter Correlations

	<u>K</u>	<u>y0</u>
K	1.00	0.00
y0	0.00	1.00

Residual Statistics

for weighted residuals

Sum of Squares ...	0.04439 ft ²
Variance	0.003699 ft ²
Std. Deviation	0.06082 ft
Mean	0.05141 ft
No. of Residuals ...	14
No. of Estimates ...	2



PRODUCT RECOVERY TEST - LATE DATA

Data Set: G:\PROGVAQTWIEPRB3LAT.AQT

Date: 04/03/98

Time: 13:35:17

PROJECT INFORMATION

Company: DSM

Client: CORCO

Project: 1093-01

Test Location: Puerto Rico

Test Well: EPRB-3 Late Data

Test Date: 11/22/97

AQUIFER DATA

Saturated Thickness: 16. ft

WELL DATA

Initial Displacement: 16. ft

Casing Radius: 0.17 ft

Screen Length: 20. ft

Water Column Height: 16. ft

Wellbore Radius: 0.33 ft

Gravel Pack Porosity: 0.2

SOLUTION

Aquifer Model: Unconfined

Solution Method: Bouwer-Rice

$K = 7.061E-07$ ft/min

$y_0 = 0.04387$ ft

Data Set: G:\PROG\AQTW\EPRB3LAT.AQT
Title: Product Recovery Test - Late Data
Date: 04/03/98
Time: 13:35:03

PROJECT INFORMATION

Company: DSM
Client: CORCO
Project: 1093-01
Location: Puerto Rico
Test Date: 11/22/97
Test Well: EPRB-3 Late Data

AQUIFER DATA

Saturated Thickness: 16 ft
Anisotropy Ratio (Kz/Kr): 1

OBSERVATION WELL DATA

Number of observation wells: 1

Observation Well No. 1: EPRB-3

X Location: 0 ft
Y Location: 0 ft

Observation Data	
Time (min)	Displacement (ft)
7.	0.03
14.	0.07
24.	0.05
29.	0.05
32.	0.06
35.	0.07
40.	0.05
44.	0.05
50.	0.05
62.	0.06
70.	0.06
80.	0.07
85.	0.08

SOLUTION

Aquifer Model: Unconfined
Solution Method: Bouwer-Rice

VISUAL ESTIMATION RESULTSEstimated Parameters

<u>Parameter</u>	<u>Estimate</u>	
K	7.061E-07	ft/min
y0	0.04387	ft

AUTOMATIC ESTIMATION RESULTSEstimated Parameters

<u>Parameter</u>	<u>Estimate</u>	<u>Std. Error</u>	
K	7.061E-07	1.899E-05	ft/min
y0	0.04387	0.01227	ft

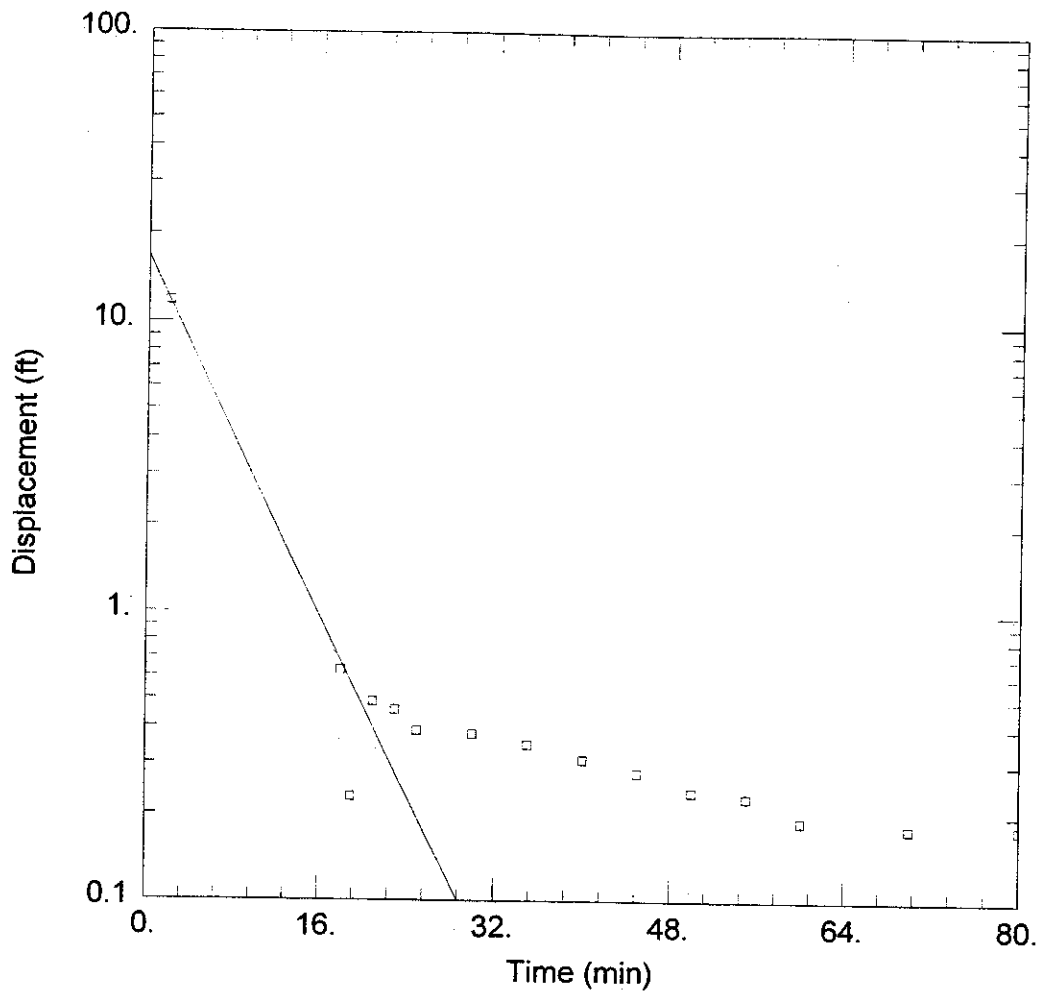
Parameter Correlations

	<u>K</u>	<u>y0</u>
K	1.00	0.88
y0	0.88	1.00

Residual Statistics

for weighted residuals

Sum of Squares ... 0.004704 ft²
Variance..... 0.0004276 ft²
Std. Deviation..... 0.02068 ft
Mean 0.01423 ft
No. of Residuals ... 13
No. of Estimates ... 2



PRODUCT RECOVERY TEST

Data Set: G:\PROG\AQTWEP\RB-6.AQT

Date: 03/23/98

Time: 13:08:51

AQUIFER DATA

Saturated Thickness: 12. ft

WELL DATA

Initial Displacement: 11.78 ft

Casing Radius: 0.17 ft

Screen Length: 20. ft

Water Column Height: 12. ft

Wellbore Radius: 0.33 ft

Gravel Pack Porosity: 0.2

SOLUTION

Aquifer Model: Unconfined

Solution Method: Bouwer-Rice

K = 0.0005615 ft/min

y0 = 16.81 ft

Data Set: G:\PROG\AQTM\EPB-6.AQT
Title: Product Recovery Test
Date: 03/23/98
Time: 13:08:42

AQUIFER DATA

Saturated Thickness: 12 ft
Anisotropy Ratio (Kz/Kr): 1

OBSERVATION WELL DATA

Number of observation wells: 1

Observation Well No. 1: EPRB-6

X Location: 0 ft
Y Location: 0 ft

<u>Observation Data</u>	
<u>Time (min)</u>	<u>Displacement (ft)</u>
2.	11.78
18.	0.63
19.	0.23
21.	0.49
23.	0.46
25.	0.39
30.	0.38
35.	0.35
40.	0.31
45.	0.28
50.	0.24
55.	0.23
60.	0.19
70.	0.18
80.	0.18

SOLUTION

Aquifer Model: Unconfined
Solution Method: Bouwer-Rice

VISUAL ESTIMATION RESULTS

Estimated Parameters

<u>Parameter</u>	<u>Estimate</u>	
K	0.0005615	ft/min
y0	16.81	ft

AUTOMATIC ESTIMATION RESULTSEstimated Parameters

<u>Parameter</u>	<u>Estimate</u>	<u>Std. Error</u>	
K	0.0005615	4.276E-05	ft/min
y0	16.81	0.5944	ft

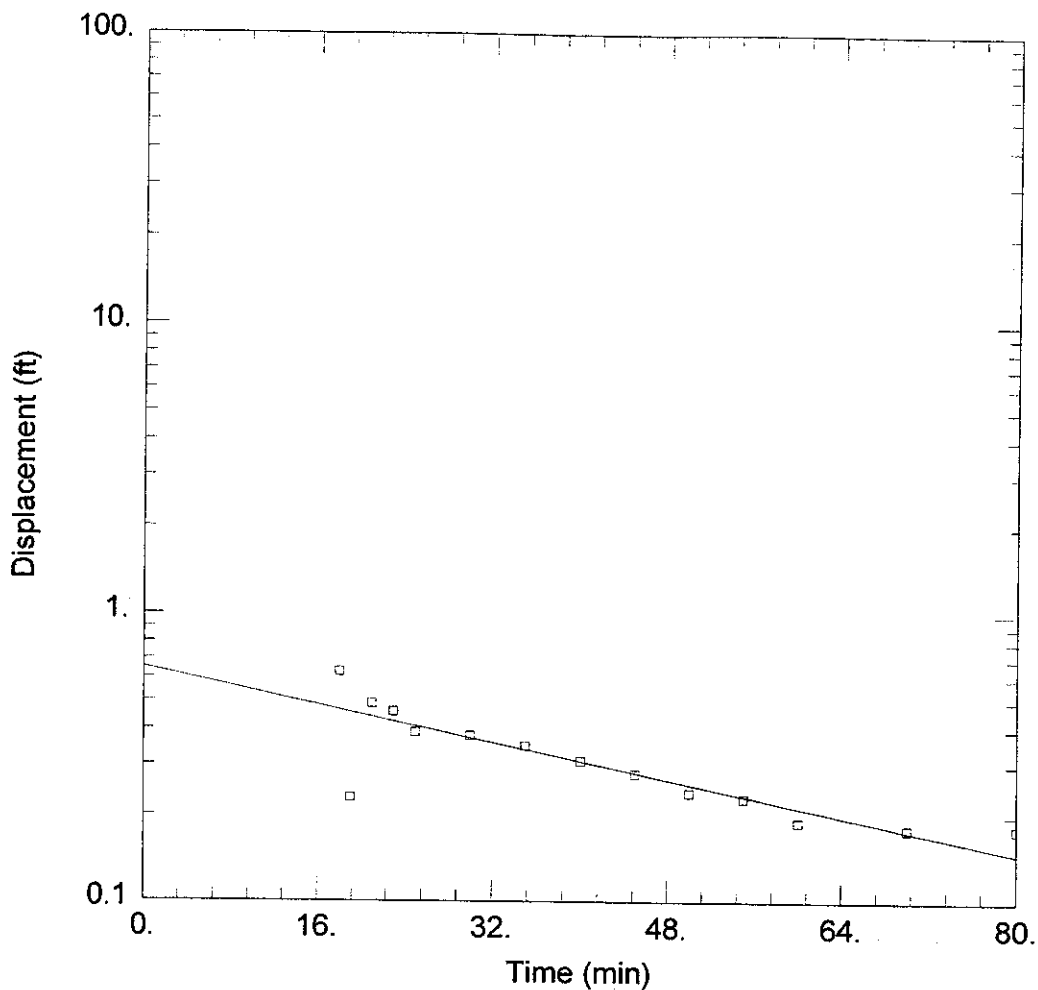
Parameter Correlations

	<u>K</u>	<u>y0</u>
K	1.00	0.82
y0	0.82	1.00

Residual Statistics

for weighted residuals

Sum of Squares ... 0.76 ft²
Variance..... 0.05846 ft²
Std. Deviation..... 0.2418 ft
Mean 0.1518 ft
No. of Residuals ... 15
No. of Estimates ... 2



PRODUCT RECOVERY TEST-LATE DATA

Data Set: G:\PROGVAQTWEPRB6LAT.AQT

Date: 03/23/98

Time: 13:07:20

PROJECT INFORMATION

Company: DSM

Client: CORCO

Project: 1083-10

Test Location: Puerto Rico

Test Well: EPRB-6

Test Date: 11/22/97

AQUIFER DATA

Saturated Thickness: 12. ft

WELL DATA

Initial Displacement: 11.78 ft

Casing Radius: 0.17 ft

Screen Length: 20. ft

Water Column Height: 12. ft

Wellbore Radius: 0.33 ft

Gravel Pack Porosity: 0.2

SOLUTION

Aquifer Model: Unconfined

Solution Method: Bouwer-Rice

$K = 5.892E-05$ ft/min

$y_0 = 0.6537$ ft

Data Set: G:\PROG\AQTM\EPRB6LAT.AQT
Title: Product Recovery Test-Late Data
Date: 03/23/98
Time: 13:06:32

PROJECT INFORMATION

Company: DSM
Client: CORCO
Project: 1083-10
Location: Puerto Rico
Test Date: 11/22/97
Test Well: EPRB-6

AQUIFER DATA

Saturated Thickness: 12 ft
Anisotropy Ratio (K_z/K_r): 1

OBSERVATION WELL DATA

Number of observation wells: 1

Observation Well No. 1: EPRB-6

X Location: 0 ft

Y Location: 0 ft

<u>Observation Data</u>	
<u>Time (min)</u>	<u>Displacement (ft)</u>
18.	0.63
19.	0.23
21.	0.49
23.	0.46
25.	0.39
30.	0.38
35.	0.35
40.	0.31
45.	0.28
50.	0.24
55.	0.23
60.	0.19
70.	0.18
80.	0.18

SOLUTION

Aquifer Model: Unconfined
Solution Method: Bouwer-Rice

VISUAL ESTIMATION RESULTSEstimated Parameters

Parameter	Estimate	
K	5.892E-05	ft/min
y0	0.6537	ft

AUTOMATIC ESTIMATION RESULTSEstimated Parameters

Parameter	Estimate	Std. Error	
K	5.892E-05	1.49E-05	ft/min
y0	0.6537	0.1024	ft

Parameter Correlations

	K	y0
K	1.00	0.91
y0	0.91	1.00

Residual Statistics

for weighted residuals

Sum of Squares ...	0.08476 ft ²
Variance	0.007063 ft ²
Std. Deviation	0.08404 ft
Mean	0.0003561 ft
No. of Residuals ...	14
No. of Estimates ...	2

APPENDIX D

MODEL CALIBRATION PARAMETERS

Appendix D. Model Calibration Parameters

Name	Symbol	Value	Units
------	--------	-------	-------

Analytical Parameters

Hydraulic Conductivity	K	2.84 e-4	feet/day
Bottom (Head)	h	0	feet
Top (Head)	h	1.5	feet
Reference Head	h	1.5	feet
Gradient	I	2 e-5	feet/feet
Recharge		0	cu.ft./day
Porosity		40	percent
Storage	S	0	unitless
Leakage		0	unitless
Time	t	1	day

Reference Head Data

Head	h	1.5	feet
Gradient	I	2 e-5	feet/feet
Angle(Direction)		200	degrees
Location	Easting	738850.6	meters
	Northing	1992416.72	meters

Well information

Radius	r	0.25	feet
Pumping Rate	Q	47	cu.ft./day

Line Sink Information

Head	h	0	feet
------	---	---	------

Pond Information

Radius	r	42.97	feet
Infiltration		0	cu.ft./day
Total Flow		0	cu.ft./day
Head	h	0	feet

APPENDIX E

MODEL VERIFICATION

APPENDIX E

```

+-----+
| 32-bit Power for Lahey Computer Systems |
| Phar Lap's 386|DOS-Extender(tm) Version 5.1 |
| Copyright (C) 1986-93 Phar Lap Software, Inc. |
| Available Memory = 30152 Kb |
+-----+

```

GLOREFLOW

(G)asoline(L)iquid(O)ptimum(R)ecovery(E)valuation
 Gasoline Product Recovery Program
 Includes Density, Viscosity, and Surface
 Tension Effects

Pumpage only from Gasoline Phase

Version 1.0

April 1998

Enter Product Thickness (Ft) 1.5000000000000000
 (Enter Zero to terminate) 1.5

Enter Allowable Well Drawdown (Ft) -1.5000000000000000
 -1.5

Enter Effective Well Radius (Ft) 0.7500000000000000
 .75

Enter Radius of Influence of Well (Ft) 225.00000000000000
 225

Enter Aquifer Hydraulic Conductivity from
 recovery test (cm/sec) 0.3000000000000000D-00
 49.9e-5

Enter Fraction of Water from Recovery Test 0.4000000000000000
 .4

Enter Fraction of Gasoline from Recovery Test 0.6000000000000000
 .6

Number of 100 meter by 100 meter cells in gasoline plue
 55.00000000000000 55

Porosity 0.4000000000000000 .4

Half-Life of Gasoline Product (Years) 5.000000000000000 5

Hydraulic Conductivity 40.00000000000000 % Freshwater
 60.00000000000000 % Gasoline (cm/sec) 0.989999992212723D-004

Intrinsic Permeability (ft**2) 0.711130798541961D-012

Fresh Water Hyd Cond, GPD/FT**2 1.36908552156852

Gasoline Hydr Cond, GPD/FT**2 3.25686687858356

Average Gradient (ft/ft) 0.232986384103843D-002

Surface tension to hydr cond force ratio (using virtual work approach)

APPENDIX E

0.319038910295718D-001
 Allowable Discharge (Gal/Month) 234.444024999453 GPM
 0.542694502313548D-002
 Est. Gasoline Plume Total Volume (GALS) = 26572228.1627463
 3552436.91109478
 Number of wells to clean-up 37.2271864640552
 Months to clean-up 3044.58840732085
 Years to clean-up w/o decay 253.715700610071
 Gasoline Balance -23019791.2516516 GALS
 Cleanup Time (Years) with decay = 18.7500000000000 closure =
 0.807465043841537D-002
 Volume Remaining After Decay (GALS) = 1974992.67453835
 Pumped Volume (GALS) = 1991004.60838998
 Closure (combined decay and pumpage, GALS) -16011.9338516234


```

program puerto
implicit none
double precision fmin,F,cleanuptime
integer time ! years
double precision HalfLife,lamba
c
c NOTE: this code is for the aquifer continuum. IT IS NOT APPLICABLE
c to discontinuities such as fractures. In this regard it is
c therefore conservative as far as time and pumpage.
c
c Assumes aquifer is water wet
c
double precision porosity
double precision totalflowwt,flowwt
integer i
double precision dhdr,r,dr
double precision avggradient
double precision watfrac,gasfrac
double precision k
double precision ncells
double precision npumps
double precision qmonth
double precision volume
double precision pi,hw,rw,re,qw,thick
double precision freshwaterE,seawaterE,oilE,oilSG,freshwaterSG,
&seawaterSG
double precision gasSG,g,oilSW,freshwaterSW,seawaterSW,gasSW
double precision heavyoildynamicviscosity,lighoildynamicviscosity
double precision freshwaterdynamicviscosity,
&seawaterdynamicviscosity
double precision gasdynamicviscosity,oilsurfacetension,
&gassurfacetension
double precision freshwatersurfacetension,seawatersurfacetension
double precision k1,k2,kavg,kintrinsic,kfreshwater,kgas
c
c References:
c Bear, J., 1972, Dynamics of Fluids in Porous Media, Elsevier
c Publishing, 764 p.
c
c Tabor, D., 1991, Gases, liquids, and solids, Cambridge University
c Press, 418 p.
c
thick=1.0 ! thickness of gasoline product, ft
hw=-1.0 ! allowable drawdown in ft at the well
rw=0.75 ! effective well radius, ft
re=100.0*3.281 ! feet, radius of influence of well
re=200.0
k=1e-4 ! cm/sec, hydraulic conductivity of aquifer
watfrac=0.40 ! fraction of liquid recovered which is water from
c the recovery test
gasfrac=0.60 ! fraction of liquid recovered which is gasoline from
c the recovery test
porosity=1.0/7.48
porosity=0.4
ncells=55.0
write(*,*)
write(*,*) ' GLOREFLOW '
write(*,*) ' (G)asoline(L)iquid(O)ptimum(R)ecovery(E)valuation '
write(*,*) ' Gasoline Product Recovery Program '
write(*,*) ' Includes Density, Viscosity, and Surface '

```

```

write(*,*)'                               Tension Effects '
write(*,*)
write(*,*)'           Pumpage only from Gasoline Phase '
write(*,*)'               Version 1.0 '
write(*,*)'               April 1998 '
write(*,*)
do while (.true.)
write(*,*)' ***** '
write(*,*)' Enter Product Thickness (Ft)                                ',thick
write(*,*)' (Enter Zero to terminate) '
read(*,*) thick
if (thick.eq.0.0) exit
write(*,*)' Enter Allowable Well Drawdown (Ft)                                ',hw
read(*,*) hw
write(*,*)' Enter Effective Well Radius (Ft)                                ',rw
read(*,*) rw
write(*,*)' Enter Radius of Influence of Well (Ft)                                ',re
read(*,*) re
write(*,*)' Enter Aquifer Hydraulic Conductivity from '
write(*,*)' recovery test (cm/sec)                                ',k
read(*,*) k
write(*,*)' Enter Fraction of Water from Recovery Test ',
&watfrac
read(*,*) watfrac
write(*,*)' Enter Fraction of Gasoline from Recovery Test ',
&gasfrac
read(*,*) gasfrac
write(*,*)' Number of 100 meter by 100 meter cells in gasoline
plum
&e ',ncells
read(*,*) ncells
write(*,*)' Porosity ',porosity
read(*,*) porosity
HalfLife=5.0 ! years
write(*,*)' Half-Life of Gasoline Product (Years) ',HalfLife
read(*,*) HalfLife
c
c source of constants
c Marks' Standard Handbook for Mechanical Engineers, 10th Edition,
c Avallone, E.A. and T. Baumeister III, 1996, McGraw-Hill
c
c bulk modulus of elasticity lbf/in**2 1 atm 68 deg F
c
c   freshwaterE=318000
c   seawaterE= 341000
c   oilE      = 200000
c   gasE      = ?
c specific gravity, dimensionless, 1 atm 68 deg F
c   oilSG = 0.907
c   freshwaterSG = 1.00
c   seawaterSG = 1.025
c   gasSG = 0.68
c gravitational constant ft/sec**2
c   g=32.2
c specific weight lbf/ft**3 1 atm 68 deg F
c   oilSW=57.0
c   freshwaterSW=62.32
c   seawaterSW=seawaterSG*freshwaterSW
c   gasSW=gasSG*freshwaterSW
c dynamic viscosity lbf-sec/ft**2 1 atm 68 deg F
c   heavyoildynamicviscosity= 9470e-6

```

```

lightoildynamicviscosity= 1810e-6
freshwaterdynamicviscosity= 20.92e-6
seawaterdynamicviscosity=22.61e-6
gasdynamicviscosity=5.98e-6
c surface tension lbf/ft 1 atm 68 deg F
  oilsurfacetension= 3.0e-3      ! ranges from 2.3-3.7e-3 in water
  gassurfacetension= 3.15e-3     ! ranges from 2.7-3.6e-3 in water
  freshwatersurfacetension=5.0e-3 ! in air
  seawatersurfacetension=5.04e-3
c
c hydraulic conductivities at 60% gasoline and 40% water from
c recovery tests, per Charles Glore, April 1998.
c
  k1=k      ! assuming hydraulic conductivity enhancement from
fractures
  k2=k      ! at the plume scale as evidenced by fracture which
c             intersects wells PT-2 and PT-3
  kavg=dlog(k1)+dlog(k2)
  kavg=kavg/2.0
  kavg=exp(kavg)
  kavg=kavg*(1.0/2.54)*(1.0/12.0) ! ft/sec
  write(*,*) ' Hydraulic Conductivity ', watfrac*100.0, ' % Freshwater
& ', gasfrac*100.0, ' % Gasoline (cm/sec) ', kavg*12.0*2.54
  kintrinsic=kavg*(watfrac*freshwaterdynamicviscosity/freshwaterSW
& +gasfrac*gasdynamicviscosity/gasSW) ! ft**2
  write(*,*) ' Intrinsic Permeability (ft**2) ', kintrinsic
  kfreshwater=kintrinsic*freshwaterSW/freshwaterdynamicviscosity
  kgas=kintrinsic*gasSW/gasdynamicviscosity ! ft/sec
  write(*,*) ' Fresh Water Hyd Cond, GPD/FT**2 ', kfreshwater*3600.*24
& .0*7.48
  write(*,*) ' Gasoline Hydr Cond, GPD/FT**2 ', kgas*3600.*24.0*7.48
c=====
c Derivation of GW flow equation used for recovery approximations
c=====
c  $q=2\pi r \text{thick} (k_{\text{gas}} dh/dr)$  NOTE: parenthesis part from Darcy's
Equation
c   r=radius, ft
c   thick=product thickness, ft
c   h=head, ft
c   q=flow, ft3/sec
c   d=total differential operator
c Rearranging:
c    $q/(2\pi dh \text{thick} k_{\text{gas}}) = r/dr$ 
c    $dh/dr = q/(2.0\pi r \text{thick} k_{\text{gas}})$ 
c    $(2\pi dh \text{thick} k_{\text{gas}})/q = dr/r$ 
c Integrating yields:
c    $(2\pi h \text{thick} k_{\text{gas}})/q = \ln(r) + B$ 
c Applying boundary condition: h=0 at r=re
c    $B = -\ln(re)$ 
c   where re=effective well radius
c Rearranging again:
c    $q = (2\pi h \text{thick} k_{\text{gas}})/(\ln(r) - \ln(re))$ 
c    $h = q * (\ln(r) - \ln(re)) / (2\pi \text{thick} k_{\text{gas}})$ 
c Integration of dh/dr for average gradient yields
c   avg gradient =  $q * (\ln(r) - \ln(re)) / (2\pi \text{thick} k_{\text{gas}})$ 
c   total avg gradient =  $q * (\ln(rw) - \ln(re)) / (2\pi \text{thick} k_{\text{gas}})$ 
c
c   pi=acos(-1.0)
c   qw=allowable discharge, ft**3/sec
c    $qw = (2.0\pi h_w \text{thick} k_{\text{gas}}) / (dlog(rw) - dlog(re))$  ! ft**3/sec
c   dhdr=0.0

```

```

dr=(re-rw)/1000.0
r=rw-dr
totalflowwt=0.0
do i=1,1001
r=r+dr
c   flowwt=qw/(2.0*pi*r)
    flowwt=qw*(2.0*pi*r)
    totalflowwt=totalflowwt+flowwt
    dhdr=dhdr+flowwt*qw/(2.0*pi*r*thick*kgas)
enddo
dhdr=dhdr/totalflowwt
c   dhdr=dhdr/1001.0
    avggradient=dhdr
    write(*,*)' Average Gradient (ft/ft) ',avggradient
c
c change from ft/ft to lbf/ft for comparison with surface tension for
c gasoline with water
c
    avggradient=gasSW*abs(avggradient)
    write(*,*)' Surface tension to hydr cond force ratio (using virtua
&l work approach)',gassurfacetension/avggradient
    write(*,*)' Allowable Discharge (Gal/Month) ',qw*60.0*7.48*1440.0*
&30.0*(1.0-gassurfacetension/avggradient),' GPM ',qw*60.0*7.48
&*(1.0-gassurfacetension/avggradient)
    qmonth=qw*60.0*7.48*1440.0*30.0 ! GALS/month for single well
    &*(1.0-gassurfacetension/avggradient) ! gallons discharge per month
c   ncells=55.0 ! number of 100 meter by 100 meter cells in gasoline
plume
volume=ncells*100.0*3.281*100.0*3.281*thick ! volume of product in
ft**3
npumps=ncells*100.0*100.0/
&((pi/4.0)*2.0*(re/3.281)*2.0*(re/3.281)) ! number of required
wells
    write(*,*)' Est. Gasoline Plume Total Volume (GALS) = ',
&volume*porosity*7.48,volume*porosity
    write(*,*)' Number of wells to clean-up ',npumps
    write(*,*)' Months to clean-up ',
&volume*porosity*7.48/(qmonth*npumps)
    write(*,*)' Years to clean-up w/o decay ',
&(volume*porosity*7.48/(qmonth*npumps)/12.0)
    write(*,*)' Gasoline Balance ',volume*porosity-qw*npumps*
&(volume*porosity*7.48/(qmonth*npumps))*60.0*1440.*30.0
    &*(1.0-gassurfacetension/avggradient)*7.48,' GALS '
cvolume*porosity*7.48-qmonth*12.0*
c   &(volume*porosity*7.48/(qmonth*npumps)/12.0),' GALS '
    lambda=-dlog(1.0d0/2.0d0)/HalfLife ! years**-1
    fmin=1d20
    do time=1,6000
    F=dlog(dble(time)/12.0)+
&lamba*dble(time)/12.0
    &-dlog(volume*porosity)+dlog(qw*(1.0-gassurfacetension/avggradient)
&*3600d0*24d0*365d0*dble(npumps))
c   write(*,*)' Years to clean-up with decay ',F
    if (dabs(F).lt.fmin.and.F.ge.0.0) then
    fmin=dabs(F)
    cleanuptime=dble(time)/12.0
    endif
    enddo
    write(*,*)' Cleanup Time (Years) with decay = ',cleanuptime,
&' closure = ',fmin
    write(*,*)' Volume Remaining After Decay (GALS) = ',

```

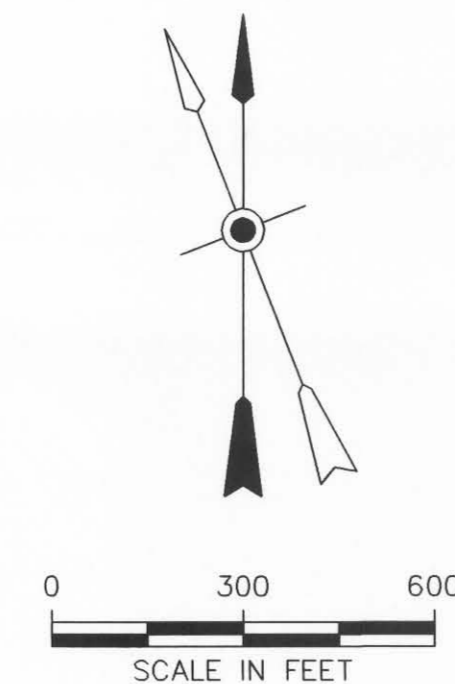
```

&dexp(-lamba*cleanup*time+dlog(volume*porosity))*7.48
  write(*,*)' Pumped Volume (GALS) = ',
&dble(npumps)*qw*(1.0-gassurfacetension/avggradient)
&*3600d0*24d0*365d0*cleanup*time*7.48
  write(*,*)' Closure (combined decay and pumpage, GALS) ',
&-(volume*porosity-dexp(-lamba*cleanup*time+dlog(volume*porosity))
&+dble(npumps)*qw*(1.0-gassurfacetension/avggradient)
&*3600d0*24d0*365d0*cleanup*time-volume*porosity)*7.48
c  &ld0/( (npumps*qw*3600d0*24d0*365d0) /(volume*porosity)-lamba)
  write(*,*)' *****
enddo
end

```



- LEGEND**
- PD-29 DELINEATION WELL
 - 22 PRODUCT RECOVERY WELL
 - PRODUCT RECOVERY PIPING
 - PRODUCT RECOVERY STORAGE TANK



**DSM ENVIRONMENTAL
SERVICES, INC.**

**CORCO FACILITY
PRODUCT COLLECTION
SYSTEM LAYOUT**

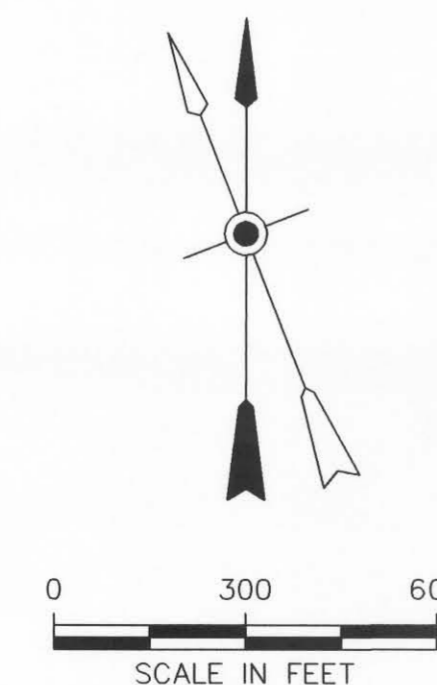
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DATE: 7/30/98	SCALE: 1"=300'	FIGURE: 3	DB NUMBER:



LEGEND

PD-29 DELINEATION WELL

22 PRODUCT RECOVERY WELL



**DSM ENVIRONMENTAL
SERVICES, INC.**

CORCO FACILITY
LOCATION OF EXISTING
MONITORING WELLS AND
PROPOSED RECOVERY WELLS

PROJECT: 1125-01	DRAWN BY: MWH	CHK'D BY:	REV:
DATE: 7/30/98	SCALE: 1"=300'	FIGURE: 1	DB NUMBER: